DECISION MATRIX SCREENING TOOL TO IDENTIFY THE BEST ARTIFICIAL LIFT METHOD FOR LIQUID-LOADED GAS WELLS

A Thesis

by

NITSUPON SOPONSAKULKAEW

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2010

Major Subject: Petroleum Engineering

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Approved by:

Co-Chairs of Committee,	Gioia Falcone
	Catalin Teodoriu
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ABSTRACT

Decision Matrix Screening Tool to Identify the Best Artificial Lift Method for Liquid-loaded Gas Wells. (August 2010)

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Co-Chairs of Advisory Committee: Dr. Gioia Falcone
Dr. Catalin Teodoriu

Liquid loading is a serious problem in gas wells. Many proven artificial lift methods have been used to alleviate this problem. However, a complete workflow to determine the most suitable artificial lift method for given well conditions does not exist.

In 2008, Han Young Park presented his thesis of decision matrix tool using a decision tree technique for data mining that determined the best artificial lift method for liquid loading in gas wells from seven artificial lift methods: plunger lift, gas lift, ESP, PCP, rod pump, jet pump, and piston pump. He determined the technical feasibility and the cost evaluation of these seven techniques. His workflow consisted of three rounds. The first round was the preliminary screening round. By using all input well conditions, the impractical techniques were screened out. In the second round, all the techniques from round one were graded and ranked. In the third round, the economic evaluation was performed by using cost for each artificial lift method and assuming the constant additional gas production per day to determine net present value (NPV) and internal rate of return (IRR).

In this thesis, we propose an extended workflow from the Han-Young's thesis for the decision matrix tool. We added integrated production simulations (reservoir to wellhead) step with commercial software in between the second and third round. We performed simulations of the various artificial lift methods to see the additional gains from each technique. We used the additional gas production resulted from simulation to calculate economic yardsticks (the third round), NPV and IRR.

Moreover, we made the decision matrix more complete by adding three more liquid unloading techniques to the decision matrix: velocity string, foam injection, and heated tubing. We have also updated all screening conditions, the technical scores, and the costs for the decision matrix from the previous study using literature reviews, information from the project's sponsor, information from service company and our own judgment.

The aim of the decision matrix is to allow operators to screen quickly and efficiently for the most suitable artificial lift method to solve the liquid loading problem under given well conditions.

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Finally, thanks to my mother and father for their encouragement and love.

NOMENCLATURE

A	Tubing cross-sectional area, ft^2
D	Diameter, ft
F	Frictional factor, dimensionless
FV	Future value, USD
g	Acceleration of gravity, ft/sec^2
i_e	Effective rate, %
n	Number of period, month, year
p	Pressure, psi
p_{sur}	Surface pressure, psi
PV	Present value, USD
q_{gc}	Gas critical rate, MMscf/d
r	discount rate, %
T_{sur}	Surface temperature, ˚F
u_m	Mixture velocity, ft/sec
v_{gc}	Gas critical velocity, ft/s
z	Elevation, ft
Z	Gas deviation factor
ρ_g	Gas density, lb/ft^3
ρ_l	Liquid density, lb/ft^3
$\bar{\rho}$	Mixture density, lb/ft^3
σ	Water surface tension, dyne/cm

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CHAPTER I

INTRODUCTION: THE IMPORTANCE OF RESEARCH

1.1 Introduction

Liquid loading is a serious problem that causes production loss in gas wells. The gas phase hydrocarbons produced from underground reservoirs will have liquid phase material associated with them. Liquids can come from condensation of hydrocarbon gas (condensate) or from interstitial water in the reservoir matrix. In either case, the higher density liquid phase must be transported to the surface by the gas. In the event the gas phase does not provide sufficient transport energy to lift the liquid out of the well, the liquids will accumulate in the wellbore. The accumulation of the liquid will impose an additional backpressure on the formation that can significantly affect the production capacity of the well. In low-pressure wells, the liquid may completely kill the well.

The sources of the liquid in gas wells that can cause liquid loading are water coning from the gas zone, aquifer water, vapor condensation in the wellbore, and hydrocarbon condensate (Lea et al. 2003).

In 1969, Turner et al. presented an attempt to model liquid loading and determine its onset. They also presented an equation to calculate the minimum velocity to remove liquid droplets from the well.

This thesis follows the style of *SPE Journal*.

After that, many proven artificial lift methods for liquid loading in gas wells have been studied and presented, such as plunger lift (Oyewole and Garg 2007), gas lift (Arachman et al. 2004), pumps (Oyewole and Lea 2008), foam injection (Schinagl et al. 2007), velocity string(Ali et al. 2003), and heated tubing (Kivi et al. 2006). However, a complete workflow to determine the most suitable artificial lift method for given well conditions does not exist.

In 2009, Park et al. presented a decision matrix tool to determine the optimal artificial lift solution for a specific liquid loading occurrence. They used a decision tree technique as the framework for the decision matrix. The decision tree is a structure that can be used to divide a large set of data into successively smaller sets by applying a series of decision rules. This division then leads to a class or value. The decision tree is one of the most popular classification algorithms in current use in knowledge discovery and data mining. It can be used for the classification and prediction of tasks and is highly effective in information extraction and pattern recognition.

The Park et al. study is a good starting point for a screening tool for the industry. However, this study has some limits in terms of the number of artificial lift methods of seven [plunger lift, gas lift, electrical submersible pump (ESP), progressing cavity pump (PCP), rod pump, jet lift, and piston pump] and the full cycle of the technical and economic evaluation of the tool based on the additional gas production from integrated production simulation.

For this thesis, we used the same basis as the Park et al. study for the decision matrix by using a decision tree technique to build the screening tool. However, we expanded the scope of work that has been done and made it more complete by adding three more artificial lift options—foam injection, velocity string, and heated tubing—to the decision matrix to total 10 methods and updating the screening criteria for each artificial lift method. We also changed the workflow of the decision matrix by performing integrated production simulations with PROSPER, MBAL, and GAP (by Petroleum Experts Ltd) to find the production profiles and decline rates of each artificial lift technique. By using the results from production simulation including the cost for each artificial lift method, we can perform the full economic evaluation.

The steps of using the decision matrix screening tool are almost the same as presented by Han-Young, which includes three rounds except for the production simulation round. Starting with the preliminary screening round, the possible artificial lift method was selected for the given well, fluid, and reservoir conditions. After that, the results from Round 1 were passed to Round 2, the technical evaluation round. In this round, the artificial lifts were ranked by technical efficiency.

Then, we stepped out of the decision matrix to do the production simulations for the selected artificial lift options. Because of the Petroleum suite limit and the limit timeframe, we performed three integrated production simulations for velocity string, gas lift, and electrical submersible pump (ESP). After we had the production profiles for each artificial lift, we went back to the final round, the economic evaluation round to determine the economic values such as NPV and IRR for the addition gas production gained from each artificial lift method.

Finally, we identified the best artificial lift method by using the results from technical evaluation and some economic values. Our technique will help operators save time and money they might otherwise spend trying many artificial lift methods by themselves.

1.2 Objective

The objective of this research was to propose the extended workflow for the decision matrix, which consists of a preliminary screening round, technical evaluation round, economic evaluation round and the integrated production simulation part to represent the real gas production with the liquid unloading techniques.

The second objective was to make the decision matrix tool more complete by

- Adding three more artificial lift methods: velocity string, foam injection, and heated tubing (total of 10 artificial lift methods)
- Updating the screening criteria
- Updating cost
- Performing economic evaluation to get the net present value (NPV) and the internal rate of return (IRR) based on the production profiles from simulation for the certain well conditions

CHAPTER II

LITERATURE REVIEW

2.1 Liquid Loading in Gas Wells

2.1.1 What Is Liquid Loading?

Liquid loading is the main problem in gas wells. Very few gas wells produce completely dry gas. The liquids are directly produced into the wellbore because of coning from an underlying zone. Not only the produced liquid comes from the reservoir, in some cases, both hydrocarbons (condensate) and water can condense from the gas stream as the temperature and pressure change during travel to the surface.

If the gas rate is too low, the pressure gradient in the tubing becomes large due to the liquid accumulation, resulting in increased pressure on the formation. As the backpressure on the formation increases, the rate of gas production from the reservoir decreases and may drop below the critical rate required to remove the liquid. More liquids will accumulate in the wellbore and the increased bottomhole pressure will further reduce gas production and may even kill the well. Late in the life of a well, liquid may stand over the perforations with the gas bubbling through the liquid to the surface. In this scenario, the gas is producing at a low but steady rate with little or no liquids coming to the surface. If this behavior is observed with no knowledge of past well history, one might assume that the well is not liquid loaded but only a low producer.

Liquid loading causes many problems to gas wells such as erratic, slugging flow and decreased production. The well may eventually die if the liquids are not continuously removed.

2.1.2 Critical Flow

In 1969, Turner et al. evaluated two correlations developed based on the two transport mechanisms using a large experimental database. Turner discovered that liquid loading could be predicted by a droplet model that showed when droplets move up (gas flow above critical velocity) or down (gas flow below critical velocity). They developed a simple correlation to predict the so-called “critical velocity” in near vertical gas wells assuming the droplet model.

In this model, the droplet weight acts downward and the drag force from the gas acts upward (Fig. 2.1). When the drag is equal to the weight, the gas velocity is at “critical”. Theoretically, at the critical velocity, the droplet would be suspended in the gas stream, moving neither upward nor downward. Below the critical velocity, the droplet falls and liquids accumulate in the wellbore. In practice, the critical velocity is generally defined as the minimum gas velocity in the production tubing required moving liquid droplets upward. The equation for the critical gas velocity and critical gas flow rate for the water droplet are shown in Eq.2-1 and Eq.2-2.

The condition to calculate the critical gas velocity and critical gas flow rate is at surface because the critical gas velocity is the highest at surface. It leads to the highest critical gas rate, which is the worst condition for the well flowing without liquid loading problem. If the flow rate of the well is higher than the critical flow rate at surface, it means that the well can flow for sure because in other part of the well, the critical flow rate is less than at the surface.

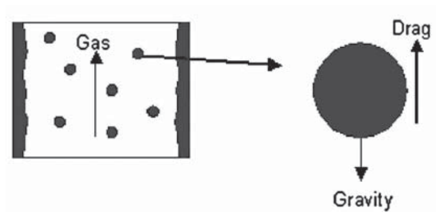

Fig. 2.1— Illustration of the concept to indentify critical velocity (Lea et al. 2003).

$$v_{gc} = 20.4\frac{\sigma^{1/4}(\rho_{lsur}-\rho_{gsur})^{1/4}}{\rho_{gsur}^{1/2}} \quad \text{(2-1)}$$

$$q_{gc} = \frac{3.067P_{sur}V_{gc}A}{(T_{sur}+460)Z} \quad \text{(2-2)}$$

Note that the actual volume of liquids produced does not appear in this correlation and the predicted terminal velocity is not a function of the rate of liquid production.

2.1.3 Multiphase Flow in Gas Well

The flow patterns in vertical gas wells can be described in four regimes, which are bubble, slug, slug-annular transition, and annular-mist flow (Fig. 2.2). The flow regimes depend on the gas flow rate. The flow regime is bubble flow at the low gas rate and changes to annular-mist flow at high gas rate.

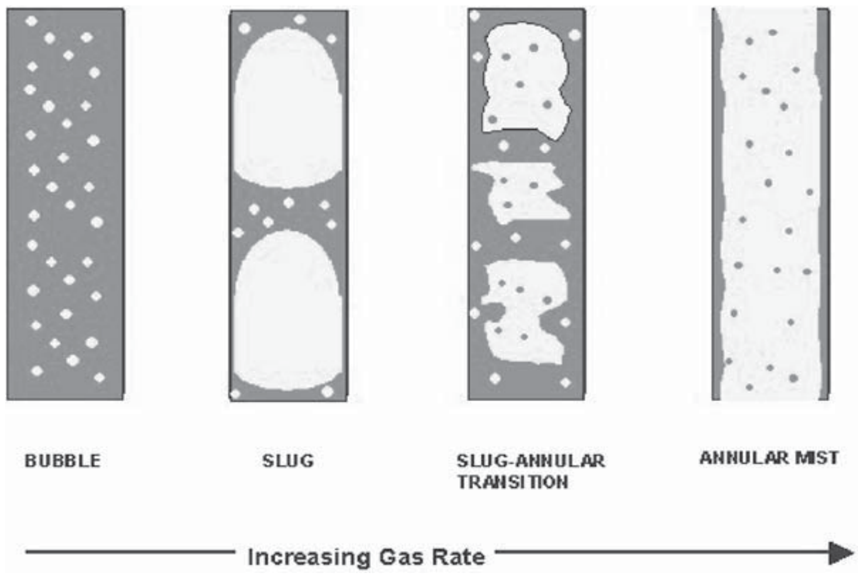

Fig. 2.2— Flow regimes in vertical multiphase flow (Lea et al. 2003).

All flow regimes can happen during the life of one gas well. Fig. 2.3 shows the progression of a typical gas well from initial production to end of life. The well may initially have a high gas rate so that the flow regime is in mist flow in the tubing but may be in bubble, transition, or slug flow below the tubing end to the mid-perforations. As time passes, the reservoir pressure and the flow rate decrease. The small flow rate, which is lower than the critical flow rate, leads to more liquid loading in the well. The flow regime changes to slug flow in the tubing and bubble flow in the casing. Finally, because there is not enough energy to overcome the hydrostatic column, the well dies.

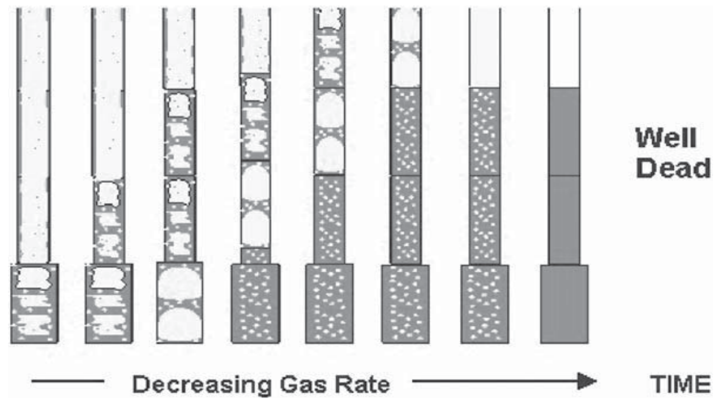

Fig. 2.3— Flow regimes during the lift of gas well (Lea et al. 2003).

2.2 Artificial Lift Option for Liquid Loading Problem in Gas Wells

In 2009, Park et al. had reviewed the literatures about the artificial lift methods for liquid loading problem. They reviewed seven artificial lift methods, which are plunger lift, gas lift, ESP, PCP, rod pump, jet lift, and piston pump.

In this study, to make the screening tool more complete, we have reviewed three more methods, which are foaming agent, velocity string, and heated tubing.

2.2.1 Foaming Agent

<u>Operation</u>

The purpose of the foaming agent is to generate foam from the gas flow. Many hydrocarbon surfactants can reduce the surface tension of water, from about 72 mN/m to about 30 mN/m. This provides a simple means to reduce the critical Turner velocity for droplet suspension by about 20%. This makes it easier to form and lift liquid droplets, which can help prevent a well from becoming liquid-loaded (Jelinek and Schramm 2005).

Moreover, foaming agents can give the result in reducing the density of the liquid. Natural gas bubbling through the liquid column containing foaming agent produces foam, which helps removing liquid from the well. Therefore, low-density foam column can be lifted from the well by the pressure that is insufficient to lift equal column of water. The foaming action decreases the hydrostatic backpressure, which increases gas production. Increased gas production further enhances the foaming action, and the well unloads (Sevic and Solesa 2006).

Furthermore, down-hole foam formation can be the stabilization of flow and reduction of pressure fluctuations in a well (Jelinek and Schramm 2005).

There are many ways to use foaming agent such as foam stick and foam injection through tubing, and foam injection through injection line. For the foam stick, foaming agents are prepared as liquids and sticks. They are solid cylindrical bars. Products can be placed in non-toxic, water-soluble plastic tube. Plastic water-soluble tube can improve action of sticks in several ways: increases melting point of the product, enables action of sticks in wells with high bottom-hole temperatures, delivers foaming agent in the most concentrated form to the bottom of gas and gas-condensate wells, which is the optimum place for water removal. Hardness of the tube prevents sticks from breaking both in the launcher and in the tubing, which increases both launching and operational efficiency.

For foam injection, it can be done by continuously inject foaming surfactant solution through tubing or the annulus. This consumes more surfactant but can lead to a more consistent unloading of the water with less pressure fluctuation (Jelinek and Schramm 2005).

Sometimes, a chemical injection line, which already has been installed together with chemical injection sub-assembled tubing, can be used to inject foam. Otherwise at a gas well with production packer, the tubing can be punched above the packer or capillary tubing should be run into the well.

Several studies have been done and show the positive results of foaming agent sine the past. In 1983, Vosika reported an economical case study. A selected foaming agent was injected into low volume gas wells in the Great Green River Basin, Wyoming. Successful installations of capillary tubings, used to inject surfactants, were described in 1999 (Awadzi et al. 1999).

In 2001, Campbell demonstrated the effectiveness and four cases of a chemical program to unload gas wells and inhibit corrosion. Applying a proposed foamer model and using all field conditions, the operating velocity was at the minimum 2.2 and at the maximum 23.9 ft/sec. The other two wells had an operating velocity around 17 ft/sec.

Lestz (2003) reported more than 100 successfully employed capillary strings in South and East Texas to resolve with surfactants problems associated with liquid loading of gas production wells. Detailed analysis of the initial 17 installations in South Texas revealed a 74 % success rate and a pay out of installation cost in less than three month. A number of other field tests have been recently been reported (Lea and Nickens 2004).

Ramachandran et al. (2003) published a computer model, which incorporates liquid loading equations with surfactant data at different salinities and oil cut in order to achieve unloading of a gas well with a foamer.

Application

Selection of the most appropriate method for solving liquid loading problem is closely related to well behavior and data availability. There are several kinds of foaming agents depending on the manufacturer. The general rules for foam agent application are shown as the following.

- Tubing and casing flows
- Relatively high GLR wells in a range 428~770scf/bbl/1000ft (250~450 m3/m3/1000m) (Sevic and Solesa 2006).
- Well with insufficient bottomhole pressure
- Wells with high salinity concentration (more than 5%), salting out phenomena can occur. Foam application can be unsuccessful.
- Horizontal wells can be unsuccessful for foam stick.
- Low water production wells can cause a soap bridge or plug in the tubing.

Advantages/Disadvantages

Foaming agents are very simple and inexpensive means of unloading low productivity gas and gas-condensate wells. There are no downhole modifications required and the surface equipment depends on the type of treatment.

2.2.2 Velocity String

<u>Operation</u>

A velocity string is simply “the next size down” for the completion. When a well is new, the production tubing is sized to handle initial gas flow rates and pressures. As wells deplete, pressure and flow rate decline. Therefore, a reasonable solution is to reduce the size of the completion to try to maintain the gas velocities required for liquid transport. Installing a smaller tubing inside the original tubing (i.e., velocity string) will create higher gas velocities and may prevent liquid loading. The installation can be up to the surface or just up to any point in tubing (Arachman et al. 2004). By installing the velocity string, the 2-phase flow changes from liquid dominant to gas dominant, which leads to higher velocity as shown in Fig. 2.4.

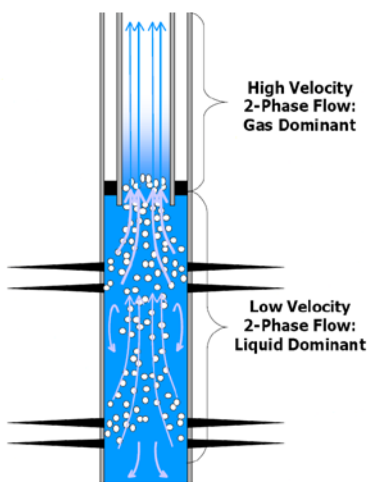

Fig. 2.4— Effect of a velocity string on production (Arachman et al. 2004).

Unfortunately, these results in a more restrictive completion, which effectively chokes the well, are reducing the overall flow rate. Besides reduced flow capability, velocity strings are only able to extend the life of a well for a limited period of time (Misselbrook and Falk 2005).

The nodal analysis of using the velocity string is shown in Fig. 2.5. The intersection of these two curves gives the rate actually produced. The velocity string moves the intersection with the current IPR curve to the left, i.e. the produced rate is reduced. However when, due to depletion the IPR curve changes, the tubing IPC curve would no longer intersect, i.e. the well cannot produce, whereas with the velocity string the well still produces. The choice is between a higher production rate over a shorter period of time and a lower production rate over a considerably longer period (and higher ultimate recovery) (Oudeman 2007).

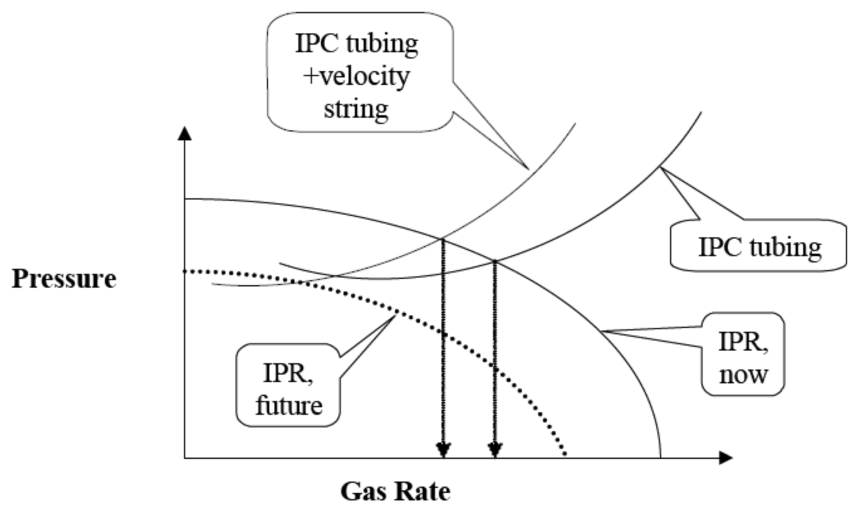

Fig. 2.5— Nodal analysis of a velocity string on production (Oudeman 2007).

<u>Applications</u>

The design for the velocity string depends on well conditions. The gas velocity must meet or exceed a minimum or critical velocity to prevent a well from loading up.

There are two popular methods for determining the minimum gas velocity: a rule of thumb widely accepted in the petroleum industry, and a theoretical correlation presented by Turner et al. (1969).

The rule of thumb sets the minimum gas velocity at 10 ft/sec. Thus, a well can be restored to flowing production if the gas velocity at the bottom of the tubing remains above 10 ft/sec. However, the actual critical velocity depends on the well conditions.

The correlation presented by Turner et al. (1969) uses a theoretical analysis of the flow regime. In order to prevent liquid loading of the well, the liquid in the tubing must be suspended as a mist (qualities above 95%) or the flow regime in the tubing must be in annular-mist flow. In these flow regimes, as long as the gas velocities exceed the settling velocity of liquid droplets, high gas velocities force the liquid out of the tubing (Rao 1999).

<u>Advantages/Disadvantages</u>

The velocity string is one of the most attractive options since it is low cost, can be carried out under pressure (i.e. there is no need to kill the well) and requires no further maintenance after installation.

Apart from mechanical considerations, such as interference with the SSSV, the main drawback of the velocity string is that the introduction of the string increases the frictional flow resistance in the well. This inevitably leads to a reduction of the productivity of the well. Hence, the result for the suppression of liquid loading is decreased production. This makes selection of the optimum size of the velocity string critical. It has to be selected such that liquid loading is avoided or at least delayed over a considerable period of time, whilst maintaining the highest possible production.

2.2.3 Heated Tubing

Operations

Heating the wellbore to reservoir conditions is a new method of eliminating fluid condensation in the wellbore (Pigott et al. 2002). This approach is the notion of heating of the fluid mix artificially modifying the thermal profile in order to decrease the overall density of the fluid by reduction of the liquid-phase fraction of the fluid and the decrease in flow friction by elimination or reduction of liquid accumulation on the tubing walls and lower the back-pressures along the tubing. This method also try to keep the velocity of the gas phase to be over than “critical flow rate” which is the minimum gas flow rate required to lift liquid phase continuously from the wellbore. Furthermore, it can also be applied to the elimination of hydrates in gas wells.

In 2006, Kivi et al studied the modeling of the thermal exchange in wellbore, two-phase flow pressure simulation. The results showed that by modifying the thermal profile of the wellbore fluid at specific locations and times, the significantly lower backpressures could be maintained and the well productivity increased. Fig. 2.6 shows three temperature profiles used in the simulations, the original profile, the temperature profile T1, and T2.

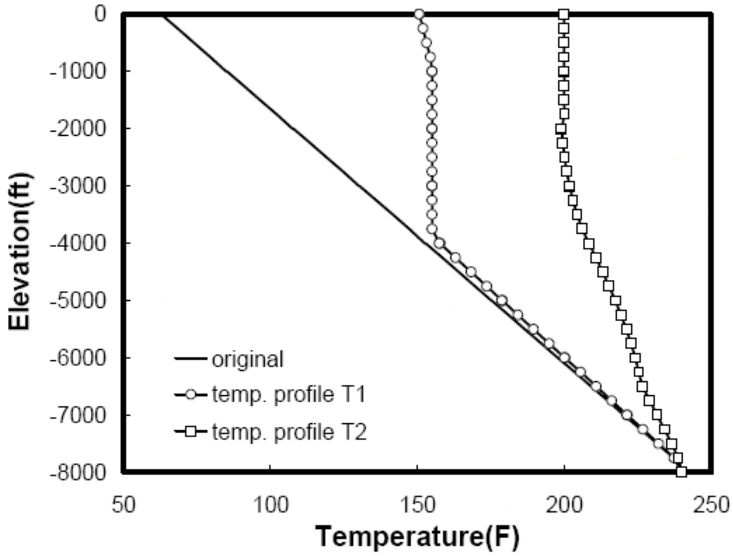

Fig. 2.6— Temperature profiles used in the simulations (Kivi et al. 2006).

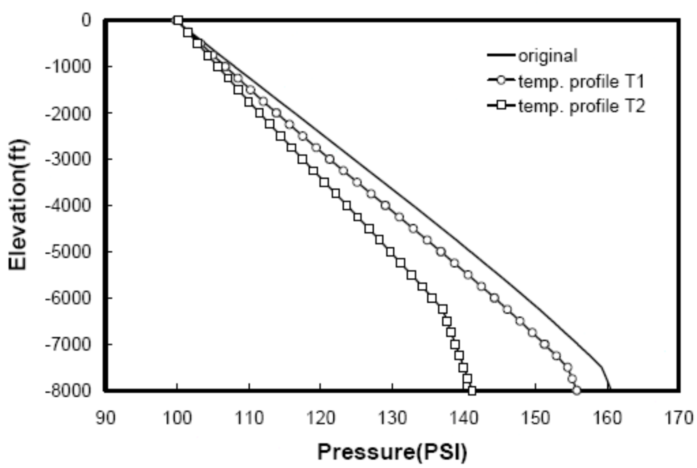

Fig. 2.7— Pressure profiles comparing the original formation temperature profile with the modified temperature profiles (T1 and T2) (Kivi et al. 2006).

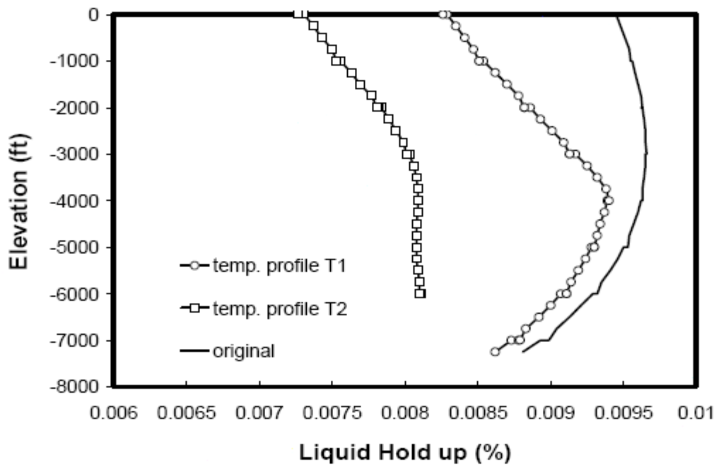

Fig. 2.8— Effects of wellbore heating on liquid hold-up (Kivi et al. 2006).

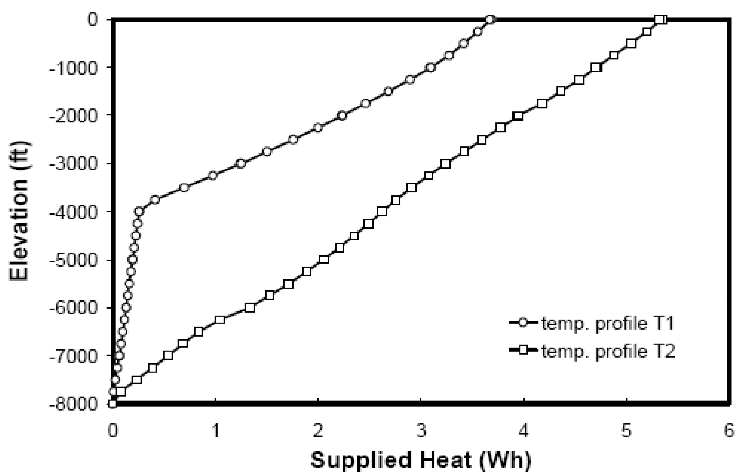

Fig. 2.9— Supplied heat to the production fluid for the temperature profiles T1 and T2 (Kivi et al. 2006).

Fig. 2.7 shows the fluid pressure inside the tubing as a function of the elevation and shows the effect of wellbore heating in the reduction of tubing back-pressure. The pressure gradients are significantly reduced by the effect of heating for the higher temperature profile. The resulting BHP has been reduced almost 13% of the original value. The change in pressure gradient is directly related to the reduction of liquid hold-up by wellbore heating as shown in Fig. 2.8. The heating reduces the liquid phase fraction of the fluid and the overall density of the mixture resulting in a smaller pressure drops from the gravity and frictional terms.

Fig. 2.9 shows the energy required are in the order of one to five watts-hour per foot of tubing. A cumulative heat required along the whole length of the tubing for the modified highest temperature is 20 kW-h. By assuming non-interrupted 24 hours/day heating, heat efficiency of 65% and an electrical cost of 7.0 cents/kW-h, the total estimated cost are about $50/day.

Fig. 2.10 shows that with the original heat, the gas velocity below 7000 ft is less than the critical velocity. It means the well is likely to get loaded with liquid. However, after heating, the modified gas velocity is above the critical velocity all along the tubing, which means there is no liquid loading up in the well.

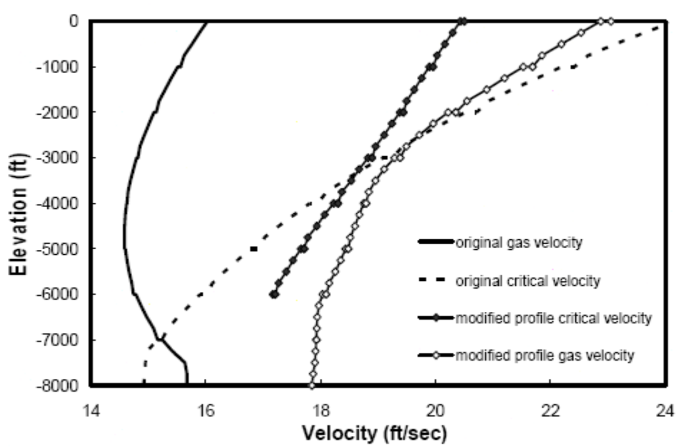

Fig. 2.10— Effect of wellbore heating on the critical and fluid velocities. (Kivi et al. 2006).

In 2002, Pigott presented another idea of liquid loading problem. They thought that the liquid occurred in the wellbore is not necessary from the formation, but formed by the condensation in the wellbore itself. By increasing the temperature and the pressure, the solubility of the water in the natural gas decreases (McCain 1990) as shown in Fig. 2.11.

By heating the tubing, the higher temperature leads to the higher solubility of water in natural gas, which means reducing of liquid loading problem in the well. Fig. 2.12 and Fig. 2.13 show the pressure and temperature profiles, respectively. The results show that after applying the heat system into the wellbore, the pressure in the wellbore reduces by 40 psia and there is no sign of the liquid as shown at the depth of 3000 ft of the before heating profile. The bottomhole and the surface temperature increase by 130 ˚F and 50˚F, respectively.

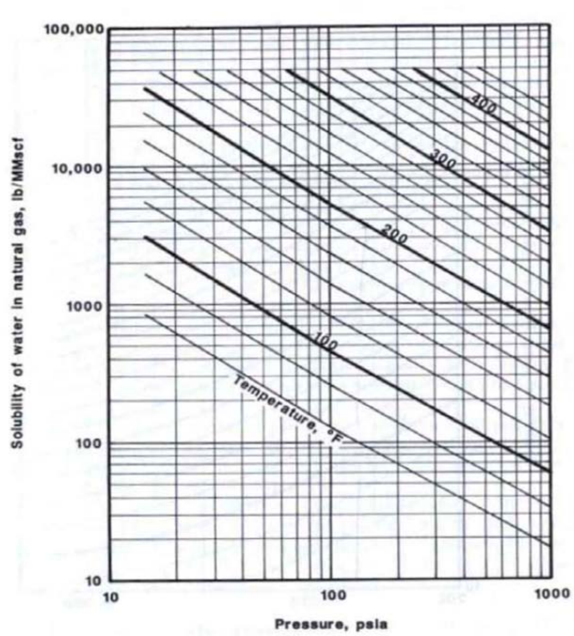

Fig. 2.11— Solubility of water in natural gas curves (McCain 1990).

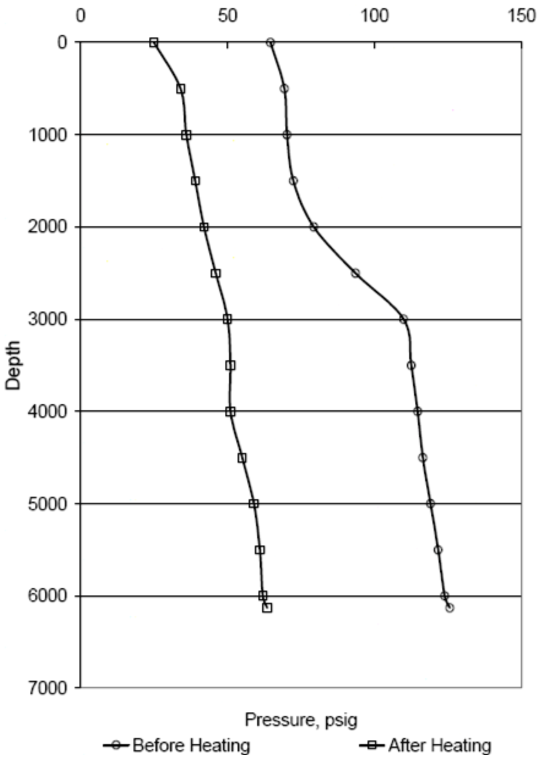

Fig. 2.12— Pressure profile before and after heating (Pigott et al. 2002).

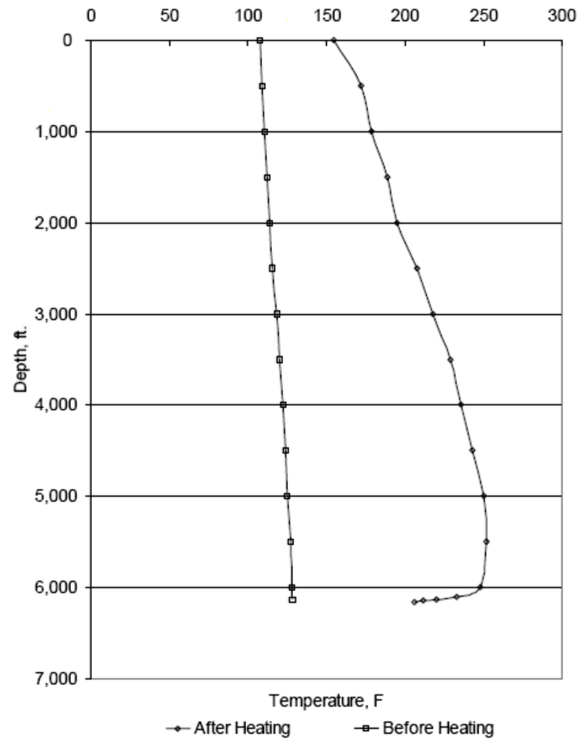

Fig. 2.13— Temperature profile before and after heating (Pigott et al. 2002).

For the installation, initially the well was killed and the tubing was pulled. The cable was attached to the tubing using bands and the cable guards. The cable was strapped to the tubing from the last joint to the surface. Some results show it may not be necessary to heat the entire wellbore. At the surface, the cable was connected to an adjustable transformer. This allowed testing the cable at several voltage settings in order to optimize the system. Once the production was optimized a permanent transformer would be ordered and installed (Kivi et al. 2006).

Applications

These criteria for this method are shown as the following.

- Low pressure gas wells
- The proved installation of 6,000-ft-tubing
- Workover required
- External power requirements

Advantages/Disadvantages

This method also allows for the use of larger tubing sizes, which reduce friction pressures by increasing flow area. Another benefit is the reduction in the abandonment pressure of the reservoir. With no fluid accumulation and limited friction pressures, lower abandonment pressures and higher production rates can be achieved.

However, the high operating costs for power consumption are expected. Modeling the system shows that 80% of the heat generated by the cable is lost to the formation (Pigott et al. 2002).

CHAPTER III

DECISION MATRIX DEVELOPMENT

3.1 Decision Tree Method

Decision tree method is an analytical approach to making decisions, especially those that have the potential to be risky or costly. A decision tree or diagram is a model of the evaluation of a discrete function, wherein the value of a variable is determined and the next action (to choose another variable to evaluate or to output the value of the function) is chosen accordingly. The method uses a graphic, known as a decision tree, which presents a set of competing alternatives as separate "branches." This schematic diagram allows managers, analysts and decision makers to map out complex sequences of decisions and strategy alternatives (Moret 1982).

The decision tree diagram consists of nodes and connecting branches. The nodes, displayed as small squares or circles, represent decision points, such as whether to invest in new technology or whether to construct a new production facility. The connecting branches represent each possible choice or outcome related to the node to which it is connected. For the new technology node, the corresponding branches represent investing and not investing. An analyst can report the costs and probabilities of success associated with each decision alternative in the decision tree.

After graphing all decision alternatives, along with corresponding probabilities, benefits and expected values, decision makers can analyze the decision tree and identify the best course of action. A completed decision tree will visually display the sequence of decisions required for each set of alternatives. Under this method, the alternative with the highest expected value is the best decision to undertake.

3.2 Decision Matrix Workflow

In 2009, Park et al. presented a decision matrix tool to determine the artificial lift that is optimum for the specific liquid loading problem in particular gas wells. This study considered seven artificial lift methods, which are plunger lift, gas lift, electrical submersible pump (ESP), progressing cavity pump (PCP), rod pump, jet lift, and piston pump. The Park et al. study is a good starting point for a screening tool developed for the industry.

After we have reviewed their study, we realize that there are many improvements we can do for this decision matrix tool. We decided to start my research from there. We started with designing a new workflow for the decision matrix. Then we wrote the new decision matrix codes, visual basic codes, based on Park's study. We added the new codes for three more artificial lift methods, which are foam agent, velocity string, and heated tubing.

We have updated some screening criteria such as the operating well depth, the offshore application, the operating volume, the operating temp, the well deviation, the casing/tubing diameter range, and the solid handling and the costs of the artificial lift methods to the decision matrix. These artificial lift criteria are provided by project's sponsor as shown in Appendix I. The artificial lift methods that we have updated are rod pump, ESP, gas lift, PCP, plunger lift, piston pump, hydraulic jet pump, and velocity string.

We have also updated the cost for each artificial lift method in the economic round by using the provided cost data from project's sponsor and service companies as shown in Appendix II.

Fig. 3.1 shows the workflow of the decision matrix. The decision matrix consists of three rounds, which are preliminary screening, technical evaluation, and economic evaluation. In each round, there are sub-screening steps inside. The possible outcomes from each step pass to the next step.

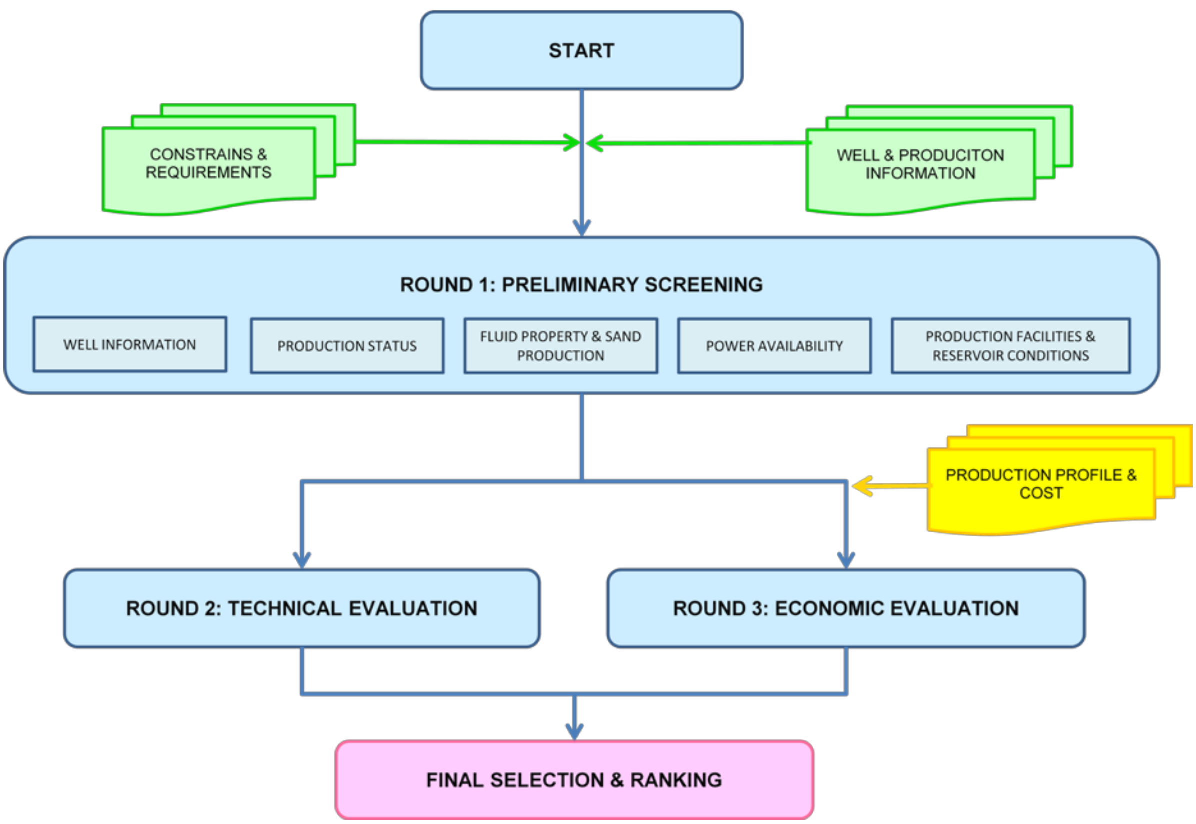

Fig. 3.1— The workflow of the decision matrix.

3.2.1 Round 1: Preliminary Screening

The preliminary screen for the suitable artificial lift method for the specific given criteria is performed in this round. The screening process is the decision tree technique shown in Appendix III. The details of the input (screening criteria) of each step are shown in Table 3.1. After screening for all steps in Round 1, the results will be passed to Round 2.

Table 3.1— Input Criteria of Round 1.

Step	Input criteria
Well information	Well location Well deviation Well depth
Production status	Operating liquid volume Operating Temperature Producing GLR
Fluid properties	Liquid Gravity Sand production
Power availability	Compressed gas available Electricity available
Production facilities	Casing & tubing diameter

The detailed explanations of each parameter are discussed below.

<u>Well Location</u>

The choices are either “offshore” or “onshore”. Each liquid loading technique is suitable for different well location. For example, rod pump is not applicable for offshore operation because of the overweight and size. Plunger lift is also not recommended to be used in offshore where downhole safety valve has been installed.

Well Deviation

This parameter asks you how much the well is deviated. From chevron's screening criteria and Park, 2009, the range for the well deviation of each liquid unloading technique is shown in Fig. 3.2.

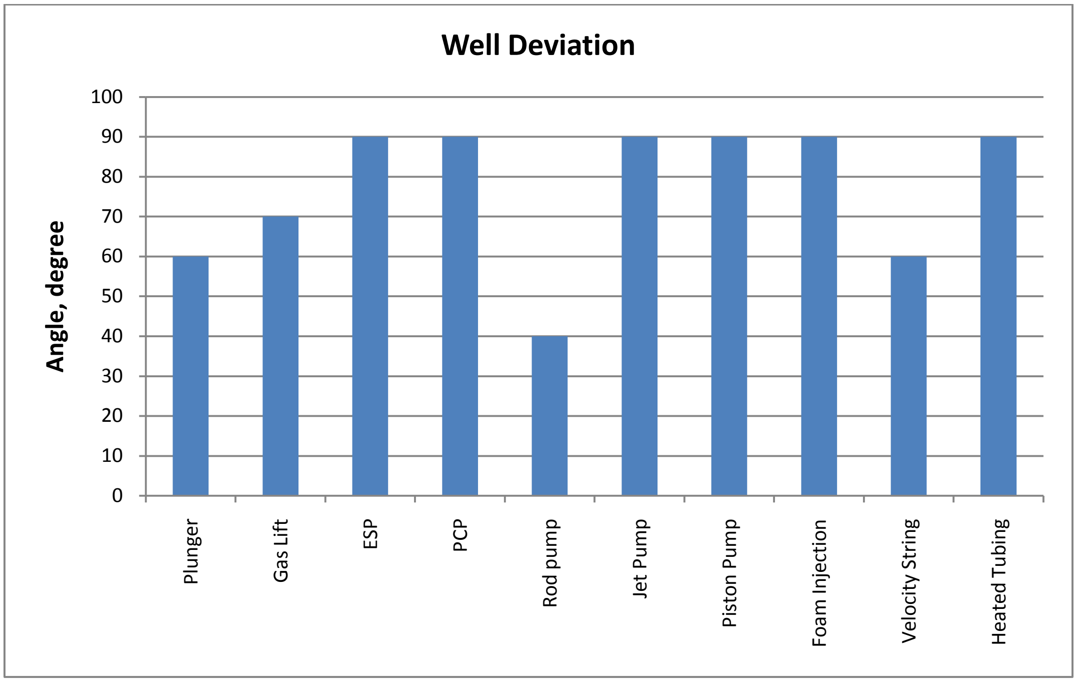

Fig. 3.2— Applicable well deviation for each liquid unloading technique (After Chevron's screening criteria and Park et al (2009)).

Well Depth

Well depth is one of the key parameter to determine the suitable artificial lift method for liquid loading problem because each method has the limitation of the equipments. From literature review, Chevron's screening criteria, Park 2009; the summary of the applicable range of depth of each method is shown in Fig. 3.3.

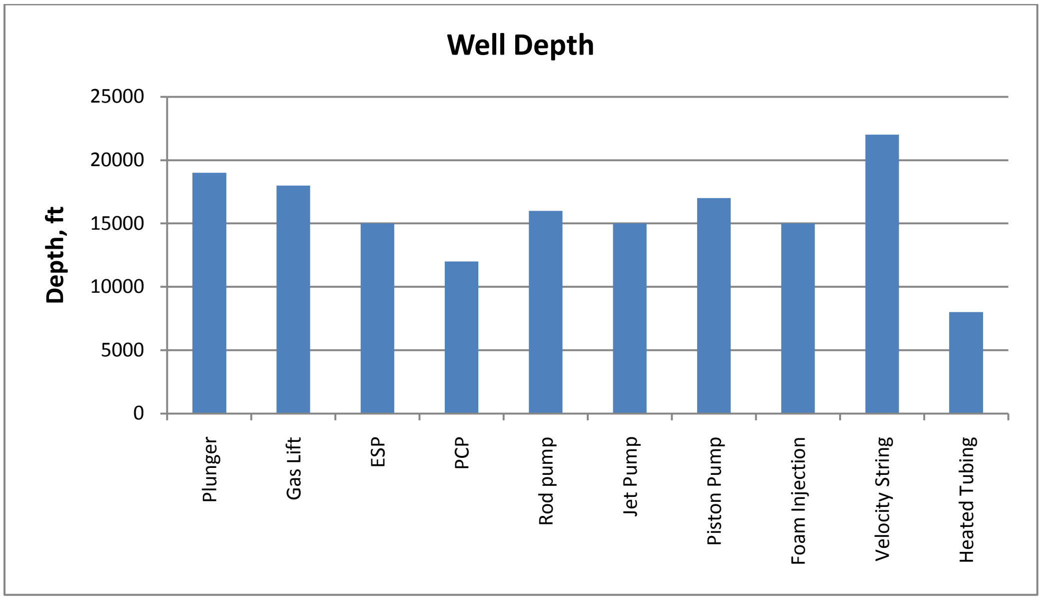

Fig. 3.3— Applicable well depth for each liquid unloading technique (After Park et al (2009), Chevron's screening criteria, and Campbell (2001), Kivi et al (2006)).

Operating Volume

Each artificial lift method has its own operation limits due to its mechanical power capacity. As shown in Fig. 3.4, ESP is the method that can handle the largest operating liquid volume. While some methods such as plunger lift, foam stick, velocity string, and heated tubing can handle only small operating liquid volume.

Gas Liquid Ratio (GLR)

From Lea (2003) rule of thumb, it states that the well must have a GLR of 400scf/bbl for every 1000 ft for application of plunger system. However, this value depends on well geometry, reservoir pressure, and resultant casing buildup operating pressure. Weatherford's brochure regarding plunger system and a paper by Morrow et al

(2006) suggest 300scf/bbl/1000ft to consider plunger system. Therefore, 300scf/bbl/1000ft is used in the decision matrix.

Pumping systems such as ESP and PCP need certain gas ratios in fluid to be operated effectively. Most pumping systems become inefficient when the GLR exceeds some high value, typically 500scf/bbl, because of gas interference (Lea, 2003). High volume of gas inside an electrical pump can cause gas interference or severe damage if the ESP installation is not designed properly (Weatherford, 2006).

For foam lift, there is a GLR rule of thumb which says that foam lift can be applied if producing GLR is in a range 428~770scf/bbl/1000ft (250~450 m3/m3/1000m) (Sevic and Solesa 2006).

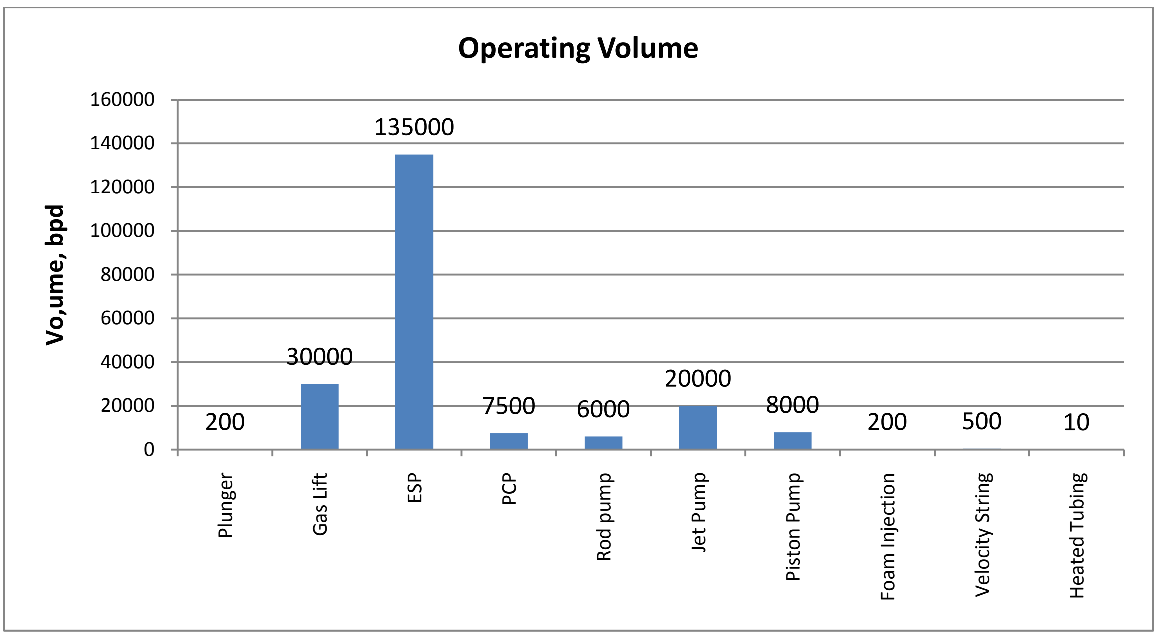

Fig. 3.4— Applicable operating volume for each liquid unloading technique (After Chevron's screening criteria, Park et al (2009) and Kivi et al (2006)).

<u>Fluid Gravity</u>

Fluid viscosity is the property that affects the working function of the lift methods. If the fluid is too vicious (below 10˚API), it causes a problem to the lift method such as gas lift. High viscous fluids may cause additional problems due to the cooling effect of the gas expanding. Fig. 3.5 shows the range of the suitable fluid gravity of each lift method.

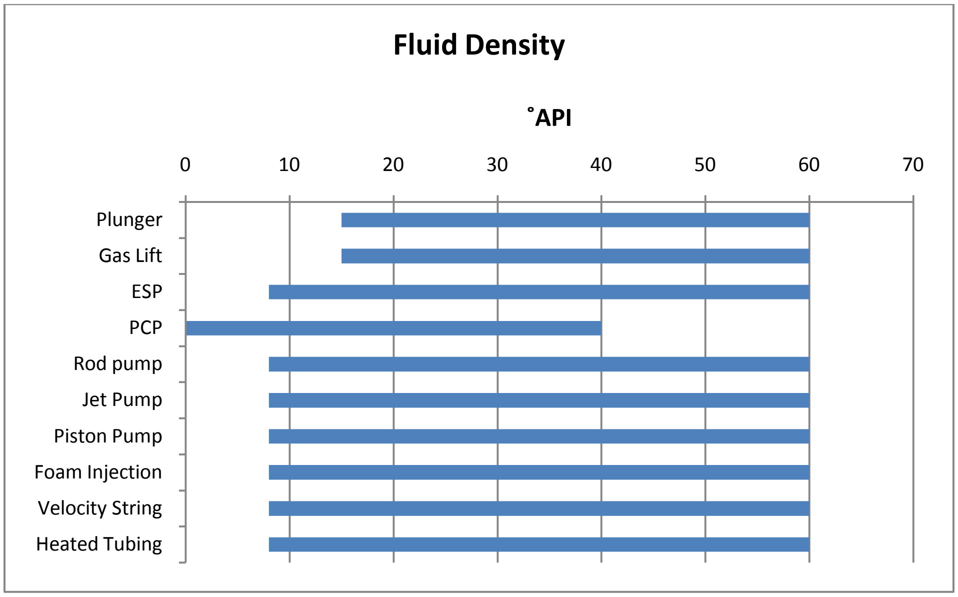

Fig. 3.5— Applicable fluid density for each liquid unloading technique (After Chevron's screening criteria, Park et al (2009)).

<u>Sand Production</u>

Sand production causes the erosion problem in all artificial lift methods. The severity depends on the methods. For example, PCP has the ability to handle the sand production. To avoid this problem, using of a downhole desander, sand separating device, are suggested.

Power Availability

The power availability is critical to the selection of artificial lift method, as it determines if power can be supplied economically. Low cost power availability is important to project profitability. Table 3.2 shows each method's power sources required for operation.

Table 3.2— Operating Power Source Required for Artificial Lift Method

	Operating Power Source
Plunger	Natural energy of well
Gas lift	Pressurized gas (Compressor w/ electric motor or gas engine)
ESP	Electric motor
PCP	Gas engine or Electric motor
Rod Pump	Gas engine or Electric motor
Jet lift	Multi-cylinder hydraulic pump w/ electric motor or gas engine
Piston pump	Multi-cylinder hydraulic pump w/ electric motor or gas engine
Foam Injection	Electricity for foam stick launcher
Velocity String	Natural energy of well
Heated Tubing	Electricity for generating heat

After we pass all the decision node in the decision tree, the remaining possible lift options are screened. We remove the options that are impossible to apply at given conditions and obtain the lifting options that are technically applicable to the given conditions. However, we still need to know which option is the best in term of technical ranking and gives you the best economic values. Therefore, we need to proceed to

Round 2 and 3 in order to rank the methods technically and economically, enabling us to find the most appropriate lifting option at given well conditions.

3.2.2 Round 2: Technical Evaluation

In this round, the preliminary screened options are evaluated by grading their technical efficiency. The previously selected options should be ranked and compared in terms of technical or practical efficiency.

The efficiency of each option depending on a well's characteristics and its technical constraints were investigated. We grade each option's efficiency and workability by five different levels. The score are 0.90, 0.75, 0.5, 0.25, 0 for excellent, good, fair, poor, and limited, respectively. The technical evaluation matrix is shown in Appendix IV. The nine categories that are in consideration are well location, well type, well depth, operating volume, solid handing, paraffin handling, corrosion handling, crooked hole, and scale. The score for each technical point of view of seven artificial lift methods (Plunger, gas lift, ESP, PCP, rod pump, jet pump, and piston pump) are based on the previous study of Park et al. We also added the score for three additional artificial lift methods (foam injection, velocity string, and heated tubing). The score in each category is based on the additional information from project's sponsor, published papers.

The two methods that we do not have the real field operation data from the operator are foam injection and heated tubing. Therefore, we have to review papers and use our own judgment to determine by technical possibility and efficiency of these two methods. The following are the detailed scoring for foam injection and heated tubing.

Foam injection:

- The score for well deviation decreases from 0.90 to 0.00 when the well are more deviated because the more angle the well, the harder that foam stick can reach the bottom of the well.
- For well depth score, we assign 0.75 for the depth of 0 to 15000 ft because the deepest depth we found from papers (Campbell et al. 2001) for foam injection is about 15000 ft. We assign 0.25 for the depth of 15000 to 16000 ft because the depth is probably more than we found from papers or the advanced technology can reach such depth.
- The highest operating volume for foam injection from paper reviews is 250 bpd (Campbell et al. 2001). The operating volume for foam injection depends on the flow rate and the rate of injection. Therefore, we assign 0.90 to volume less than 200 bpd. We decrease the score for the higher operating volume because the more volume, the less efficiency to create foam (0.50 for 200 to 500 bpd, and 0.25 for 500 to 6000 bpd).
- We assign 0.75 for the solid handling because the solid is not effect to the lifting process of the well but it may be a block part for foam stick.
- We assign 0.25 for the paraffin handling because paraffin can block the foam stick to go down and the flow to go up.
- We assign 0.75 for the corrosion handling because the corrosion depends on the coating of the well, not effecting by foam.
- We assign 0.50 for the crooked hole (average value from well deviation).

- We assign 0.25 for the scale because scale can block the foam stick to go down and the flow to go up.

Heated tubing:

- The score for well deviation are all the same (0.75) for all deviated well because the efficiency of this method depends on the length of the heating system and the power supply.
- The deepest depth from paper reviews is 8000 ft (Kivi et al. 2006). Therefore, we scored 0.75 for this depth range.
- The highest operating volume from paper reviews is about 10 bpd. The operating volume for heated tubing depends on the diameter of the producing string and the flow rate. Therefore, we assign 0.90 to volume less than 200 bpd. We decrease the score for the higher operating volume (0.5 for volume between 200 to 500 bpd and 0.25 for volume between 500 to 6000 bpd).
- We assign 0.50 for the solid handling because the solid particles can absorb heat and lead to heat loss from liquid.
- We assign 0.75 for the paraffin handling because heating helps prevent paraffin to form.
- We assign 0.75 for the corrosion handling because the corrosion depends on the coating of the well, not by heating.
- We assign 0.75 for the crooked hole (average value from well deviation).

- We assign 0.50 for the scale because heating may increase the solubility of the ion in the liquid and decrease the chance of scale precipitation.

However, all score on workability and efficiency can be properly changed or modified by the user.

Fig. 3.6 shows the example result after the screened options are graded. From this example, seven artificial lift methods, jet pump, gas lift, rod pump, piston pump, heated tubing, velocity string, and foam stick are passed. Jet pump has the highest score from grading. It means that jet pump is the most suitable artificial lift method for dealing with liquid loading for these specific well conditions.

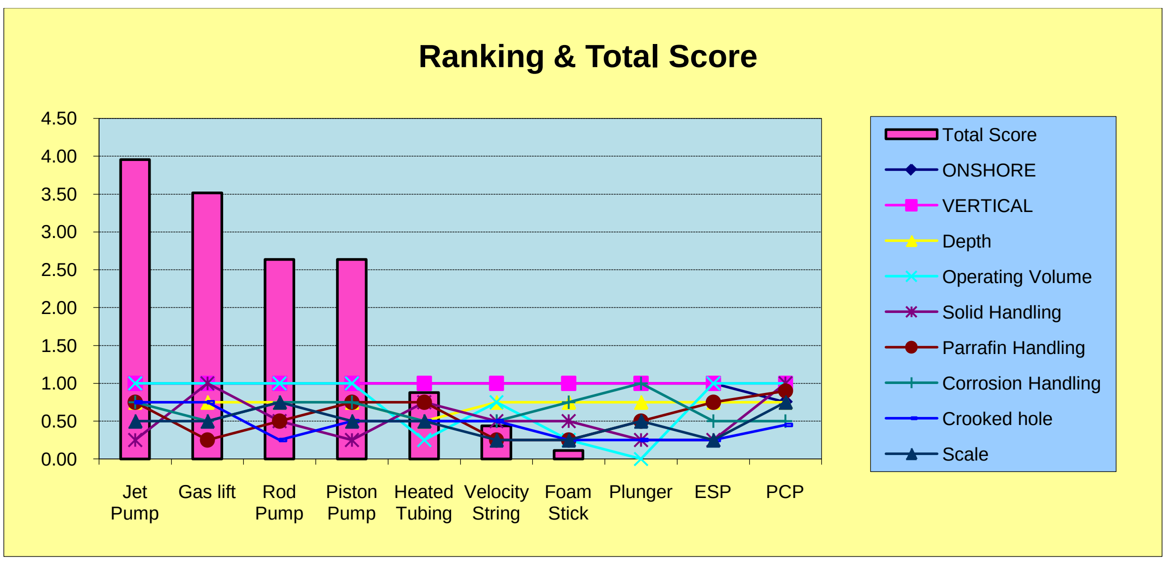

Fig. 3.6— Example results after grading evaluated.

3.2.3 Production Profile

We step out the decision matrix to determine the production profile of each artificial lift method. By using the production simulation program such as Petroleum

Expert package, GAP, MBAL, and PROSPER, we can create and simulate a syntactic case and get a possible production profile of each lift technique. In this study, we determine three lift methods, which are the velocity string, gas lift, and ESP.

These production profiles are back to the decision matrix to perform economic evaluation. The details of production simulation will be discussed in Chapter IV.

3.2.4 Round 3: Economic Evaluation

The additional gas production gained from the production simulation of the artificial lift methods combine with the capital expenditure, operation expenditure, and expected income will be used to determine the economic justification and select the best artificial lift that gives the best economic result by using net present value (NPV) and internal rate of return (IRR).

Net present value (NPV) is the method of discounting future streams of income using an expected rate of return to evaluate the current value of expected earnings. It calculates future value in today’s dollars. NPV may be used to determine the current value of a business being offered for sale or capitalized.

Internal rate of return (IRR) is the discount rate at which the present value of the future cash flows of an investment equals the cost of the investment or the discount rate with a net present value of zero. The detailed calculations are presented in Chapter V.

Eventually, by considering both of the technical evaluation and the economic evaluation, the final decision can be made.

CHAPTER IV

PRODUCTION SIMULATION

To evaluate the economic, the production profiles and the decline rates of each artificial lift methods have to be determined. The integrated reservoir-wellbore-models have been simulated using Petroleum Expert package, GAP, MBAL, and PROSPER.

4.1 Liquid Loading Cut-off

As we are studying the artificial lift methods to solve the liquid loading effect in gas wells, we have to simulate the liquid loading condition in gas wells. However, the Petroleum Expert package has no option to simulate or automatically monitor liquid loading. Therefore, we have to do a manual cut-off.

First, we tried to calculate the cut-off by using Turner equation, which mentioned in Chapter II. After paper reviews, the constant of 20.4 in Turner equation is too high. We used 2.04 as suggested from Petroleum Expert as shown in Eq.4-1. We exported the results of the simulation from GAP. We used Eq.4-3 to calculate gas densities because it was not provided by GAP. Then, we could calculate the Turner velocity from Eq.4-1 and the Critical rate from Eq.4-2 (Z factor is calculated from Beggs and Brill and corrected Standing correlations, Eq.4-4 to 4-8).

$$v_{gc} = 2.04 \frac{\sigma^{1/4}(\rho_{lsur} - \rho_{gsur})^{1/4}}{\rho_{gsur}^{1/2}} \quad (4\text{-}1)$$

$$q_{gc} = \frac{3.067 P_{sur} V_{gc} A}{(T_{sur} + 460)Z} \quad (4\text{-}2)$$

$$\rho_{gsur} = \frac{p_{sur} 28.97 \gamma_g}{R T_{sur}} \quad (4\text{-}3)$$

$$Z = A + (1 + A)exp^{-B} + CP_r^D \quad (4\text{-}4)$$

$$A = 1.39(T_r - 0.92)^{0.5} - 0.36T_r - 0.101 \quad (4\text{-}5)$$

$$B = P_r(0.62 - 0.23T_r) + P_r^2 \left(\frac{0.066}{T_r - 0.86} - 0.037\right) + \frac{0.32P_r^6}{\exp\left(20.723(T_r - 1)\right)} \quad (4\text{-}6)$$

$$C = 0.132 - 0.32logT_r \quad (4\text{-}7)$$

$$D = \exp\,(0.715 - 1.128T_r + 0.42T_r^2) \quad (4\text{-}8)$$

However, the problem is that we should not use the calculated Turner critical rate to compare directly with the resulted gas rate from GAP because they are calculated from different basis. Turner equation is not based on any petroleum experimental correlation or other empirical or mathematical flow models like those that GAP does. Turner is based on only the surface PVT properties of gas and liquid (liquid surface tension, gas density, water density, and gas compressibility factor), pressure and temperature at surface, and the tubing cross-sectional area. Therefore, we do not compare the same things (not apple to apple).

Second, we looked into PROSPER and knew that PROSPER can flag the liquid loading region. PROSPER calculate the turner velocity by varying WGR. It also calculates the actual gas velocity by using flow model equation. Then, PROSPER match

Turner velocity and the actual velocity for that WGR. Therefore, we can get the corresponding actual gas rate from that matched Turner velocity and the actual gas velocity for specific WGR. However, the PROSPER model is the static model (no production). We need to link GAP model (dynamic model) to PROSPER model (static model) to check Tuner cut-off in every time step of production. Unfortunately, we cannot do that. Therefore, we have to use the average Turner critical rate from PROSPER (varied WGR) to be a cut-off for liquid loading region and assume that this cut-off can represent the liquid loading region in GAP (dynamic model).

We also assume that this critical gas velocity and rate are the minimum value that the well is still flowing. If the gas rate is below the critical gas rate, the well dies, which is not realistic. In the real production, the well may still flow for some times after the rate reach Turner critical rate.

To represent the real production data, we create two set of the synthetic input reservoir, fluid, and well data, which capture the liquid loading behavior: has zero or very low water rate at the beginning, rapidly increase water rate, and the well die finally. The two set of data are the low and the high production cases. We use these sets of input data for all simulations (base case and three artificial lift methods). The input data are summarized in Table 4.1 and Table 4.2 for the low production and high production cases, respectively.

Table 4.1— Synthetic Reservoir, Fluid, Well Input Data for Low Production Rate Case.

Reservoir Properties	
Pressure, psig	3500
Temperature, degF	170
Porosity	0.2
Connate water saturation	0.2
Original gas in place	5000
C	0.00113
n	0.9
Small pot water influx model	
Aquifer volume, MMft3	5000
Fluid Properties	
Gas gravity, sp.gravity	0.65
Condensate gas ratio, STB/MMscf	0
Water salinity, sp.gravity	1.1
Well schematic	
Vertical well	
Tubing depth, ft	9900
Casing Depth, ft	10000
Tubing inside diameter, inches	2.992
Casing inside diameter, inches	6.1

Table 4.2— Synthetic Reservoir, Fluid, Well Input Data for High Production Rate Case.

Reservoir Properties	
Pressure, psig	3500
Temperature, degF	170
Porosity	0.2
Connate water saturation	0.2
Original gas in place	5000
Reservoir permeability, md	5
Reservoir thickness, ft	40
Drainage area, acres	120
Dietz shape factor	31.62
Perforation interval, ft	40
Skin	2
Small pot water influx model	
Aquifer volume, MMft3	5000
Fluid Properties	
Gas gravity, sp.gravity	0.65
Condensate gas ratio, STB/MMscf	0
Water salinity, sp.gravity	1.1
Well schematic	
Vertical well	
Tubing depth, ft	9900
Casing Depth, ft	10000
Tubing inside diameter, inches	2.992
Casing inside diameter, inches	6.1

4.2 Base Case

The base case simulation is base on the vertical gas well with all input parameters shown in section 4.1. There is no artificial lift helping lift the liquid from the well. To simulate the realistic case, we determine two base cases, the low rate production well and the high rate production well.

4.2.1 Low Production Rate Well

The results from this low production well base case are shown in Fig. 4.1 and Fig. 4.2. The maximum gas production rate is 2.67 MMscf/d and gradually declines to 2.00 MMscf/d in 4 years. Then the well dies because the gas rate is less than the critical velocity, which is 1.72 MMscf/d. The water rate exponentially increases to the maximum of 1270 STB/d. The gas recovery factor for base case is about 81.5%.

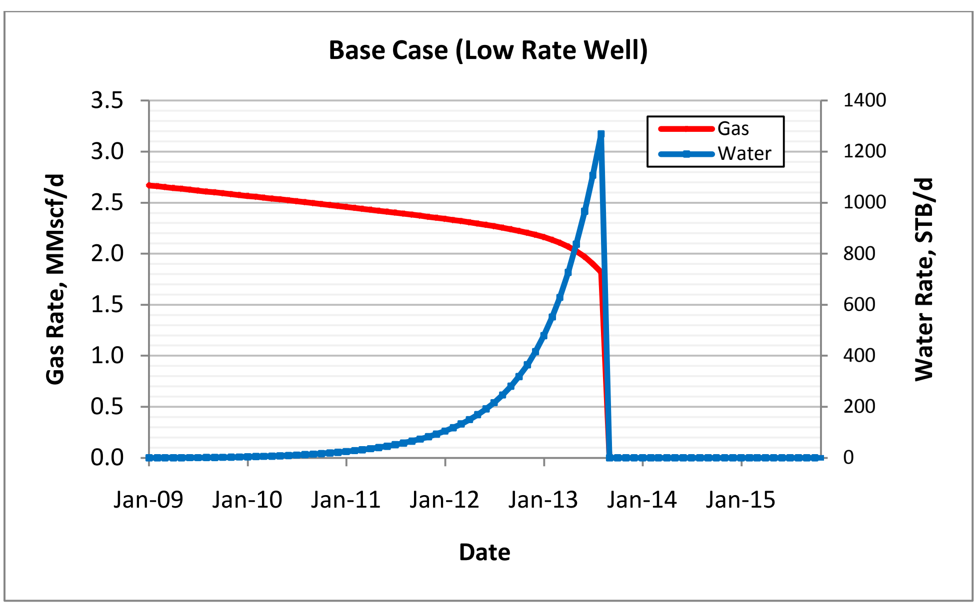

Fig. 4.1— Gas and water production rate of base case (Low rate well).

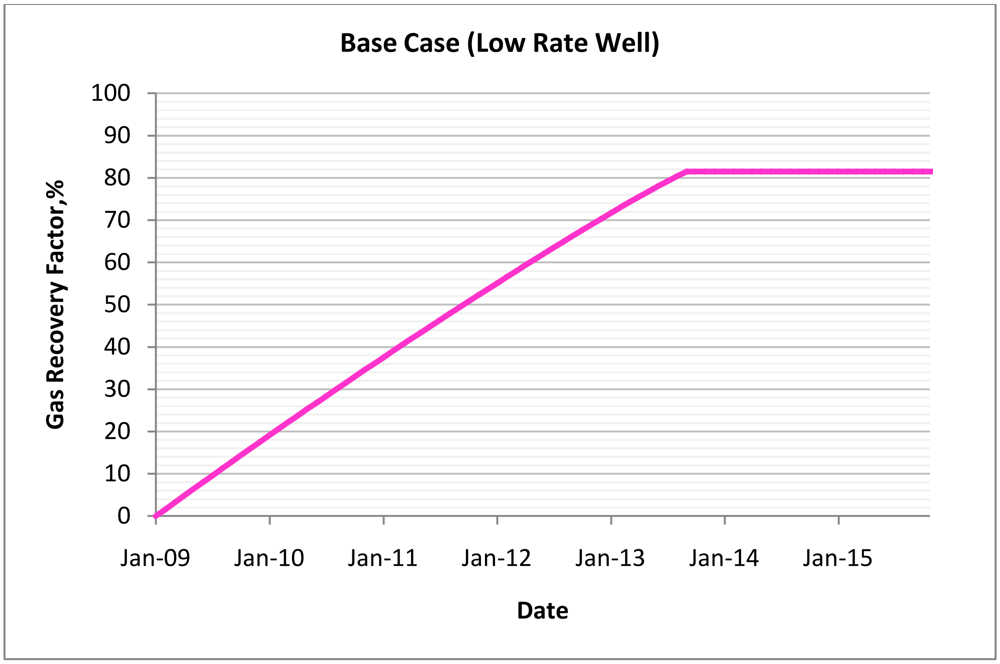

Fig. 4.2— Gas recovery factor of base case (Low rate well).

4.2.2 High Production Rate Well

The results from this high production well base case are shown in Fig. 4.3 and Fig. 4.4. The maximum gas production rate is 13.67 MMscf/d and gradually declines to 10.00 MMscf/d in 1 year and 9 months. Then the gas rate rapidly drops to 2.00 MMscf/d in 4 months while the water rate exponentially increases to the maximum of 1165 STB/d. The well dies after that because the gas rate is less than the critical velocity, which is 1.72 MMscf/d. The gas recovery factor for base case is about 71.8%.

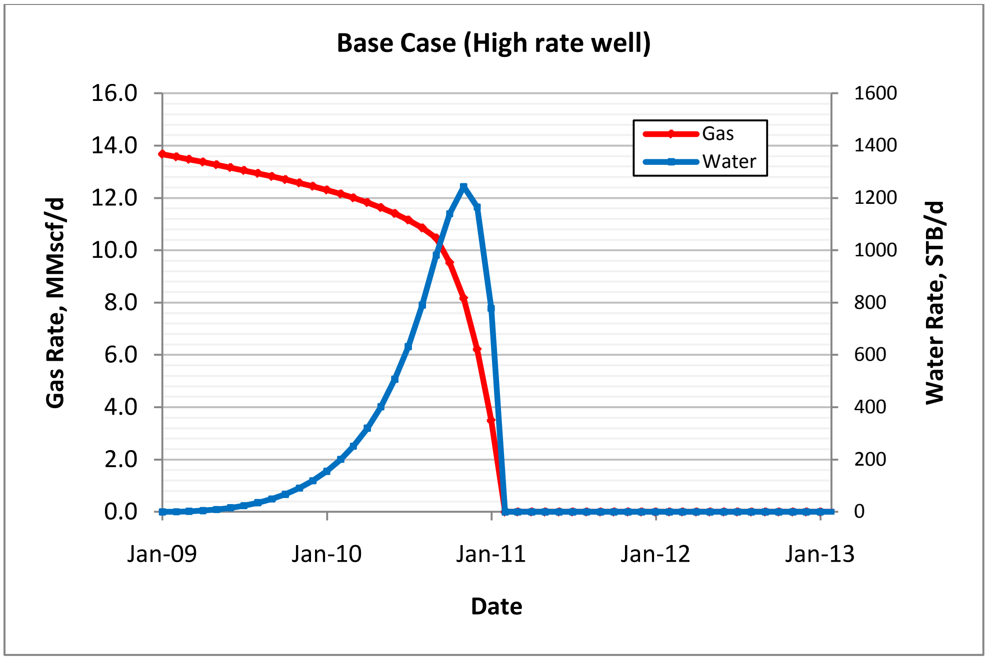

Fig. 4.3— Gas and water production rate of base case (High Rate Well).

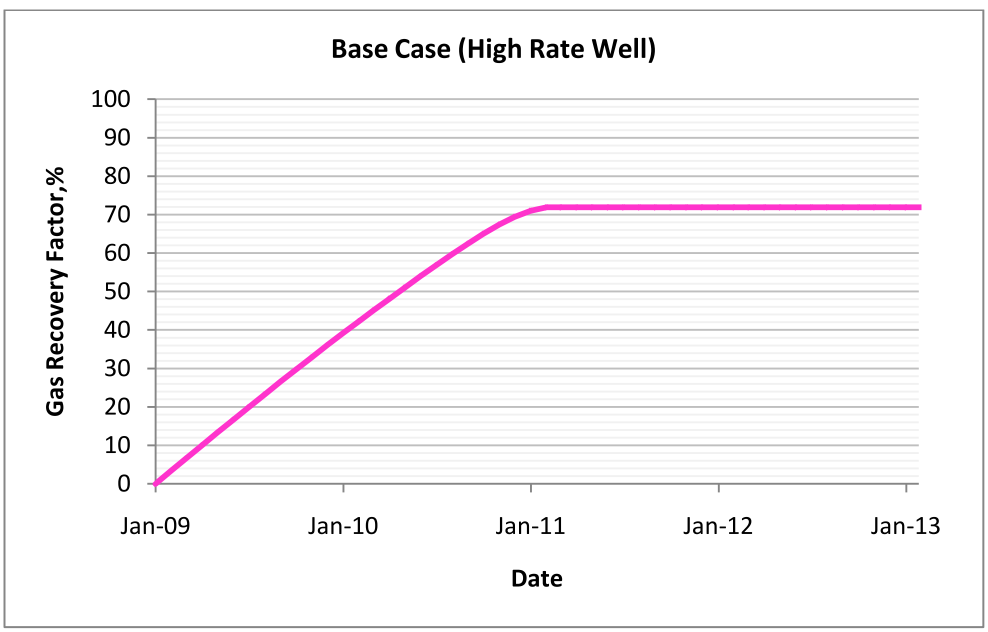

Fig. 4.4— Gas recovery factor of base case (High Rate Well).

These results of base cases are used to compare to the other cases with artificial lift methods. The artificial lift methods should be considered to help produce gas with liquid and improve the gas recovery factor. In this thesis, we simulate three artificial lift methods, which are velocity string, gas lift, and ESP. The details of each artificial lift type are shown as the following.

4.3 Velocity String

The model to simulate velocity string in gas well is relatively simple than other artificial lift methods. The velocity string is the smaller inside diameter pipe section that help to increase the fluid velocity in the production string.

To simulate the velocity string, the smaller tubing inside diameter has been applied. From Fig. 4.5, well W1 (base case) has the base case tubing inside diameter of 2.992” inches. Well W2 simulates the smaller tubing inside diameter of 2.441”, 1.995”, and 1.692” inches.

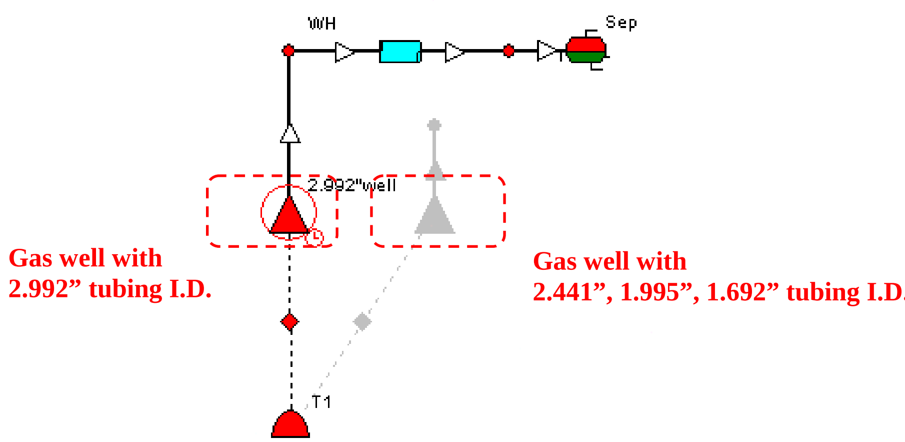

Fig. 4.5— GAP model simulates the velocity string in gas well.

The sensitivities cases to determine the effect of the velocity string are performed. We switch the production string to the smaller sizes just before the well reach the maximum water production to see the unloading effect of the velocity strings. We assume 1-month down time for the installation of the velocity string. The well dies by using the critical gas rate to be a cut-off. The critical gas rate for tubing inside diameter of 2.992”, 2.441”, 1.995”, and 1.692” inches are 1.72, 1.29, 0.86, 0.58 MMscf/d, respectively.

4.3.1 Low Production Rate Well

Fig. 4.6 and Fig. 4.7 show the gas and water production rates of the base case and the sensitivity cases for the low production well. Fig. 4.8 shows the recovery factor for all the case. The case that changes from 2.992” tubing to 1.692” tubing is the optimum case and get the highest recovery factor of 84.4% which increased from the base case 2.9%. These results will be used to evaluate the economic values, net present value (NPV) and internal rate of return (IRR) in the economic evaluation part later on.

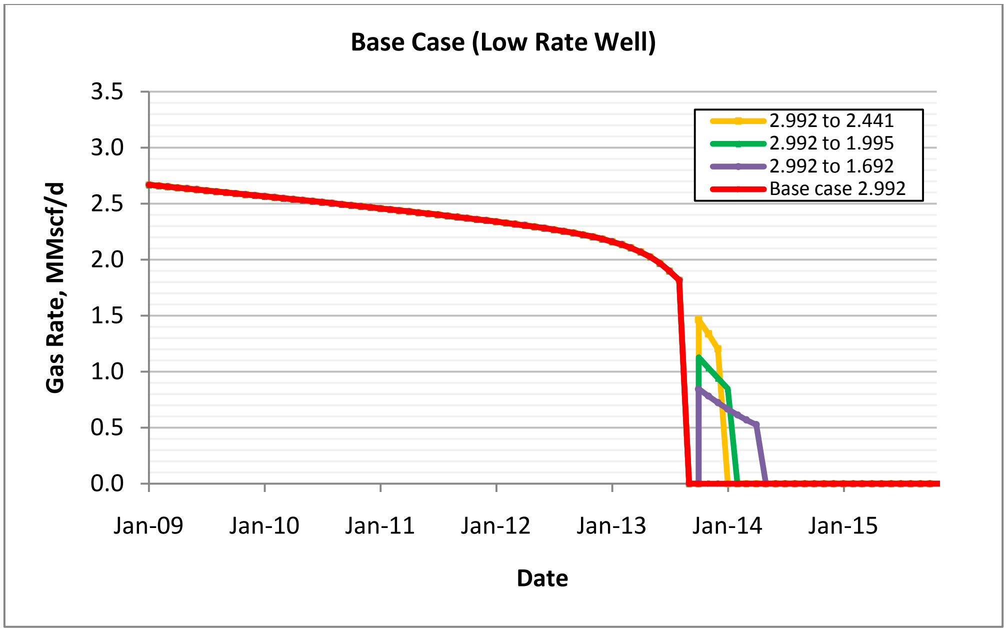

Fig. 4.6— Gas production rate of base case and sensitivity cases for velocity string simulation of low production well.

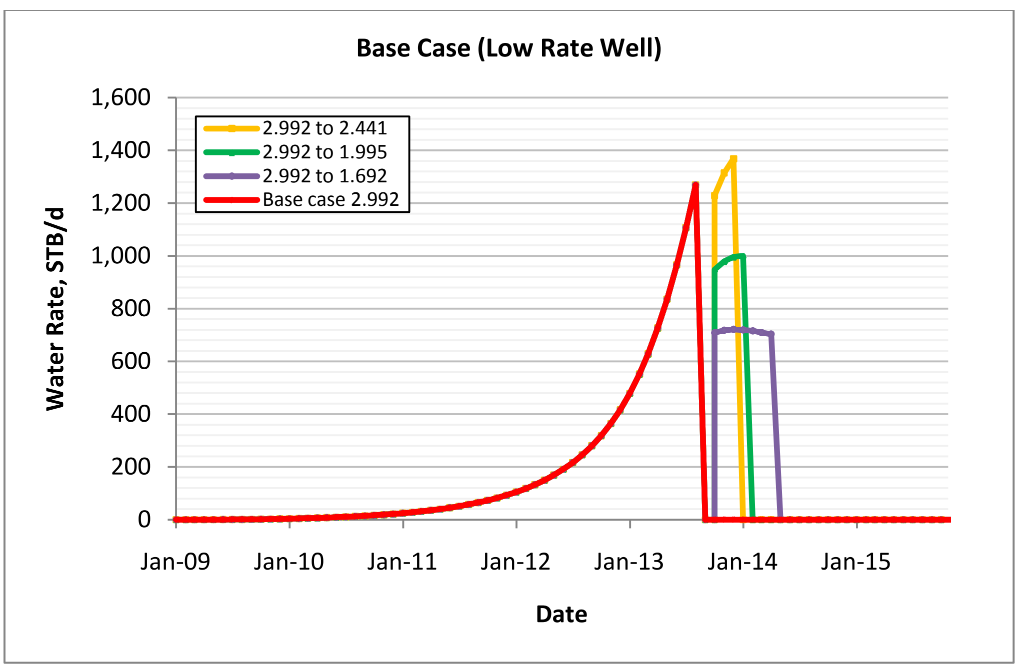

Fig. 4.7— Water production rate of base case and sensitivity cases for velocity string simulation of low production well.

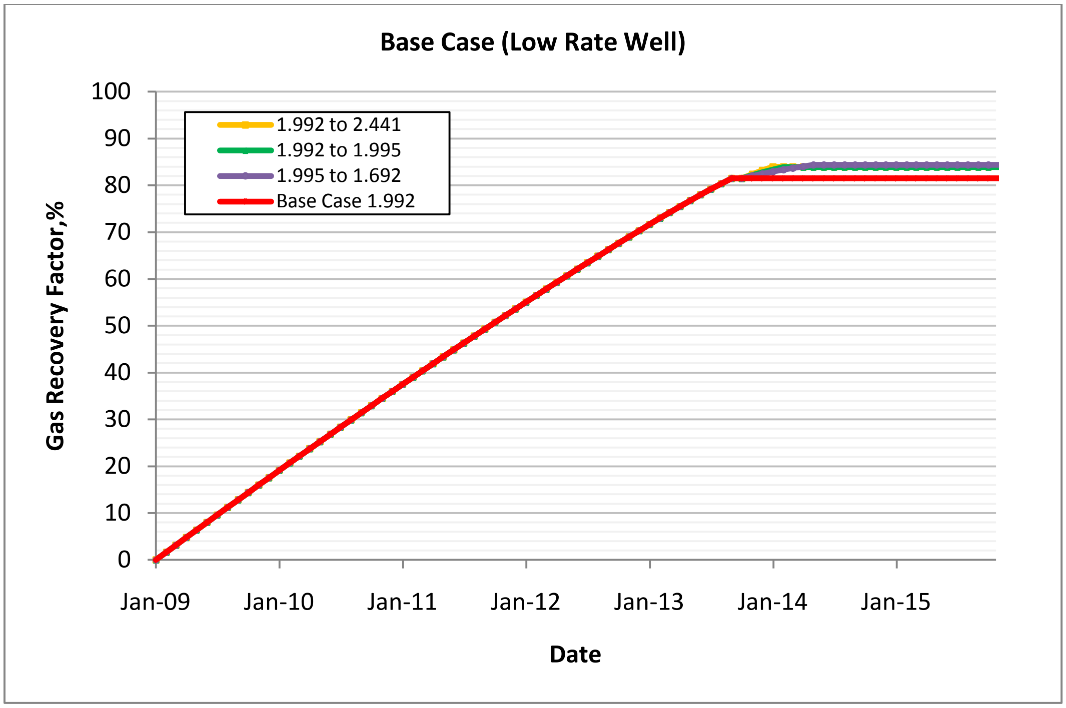

Fig. 4.8— Gas recovery factor of base case and sensitivity cases for velocity string simulation of low production well.

4.3.2 High Production Rate Well

The concept of switching a production string to a smaller one for the high production well is the same as the low production well. The differences are the input parameters. Fig. 4.9 and Fig. 4.10 show the gas and water production rates of the base case and the sensitivity cases for the high production well. Fig. 4.11 shows the recovery factor for all the case. Unfortunately, the base case is the optimum case and gets the highest recovery factor of 71.9%. The other sensitivity cases have lower recovery factor than the base case. It means that for the high production well, do nothing case is better than switching to the smaller producing strings. This is because in the high rate well, the frictional and acceleration terms dominate the pressure drop in the well. The smaller tubing sizes we have, the more effect of the frictional and acceleration terms are. The Hagedorn-Brown correlation for two-phase flow is shown in Eq. 4-9. When the tubing string is smaller, the mixture velocity is higher. In this case, the higher mixture velocity makes the higher pressure drops. The increase in pressure drop from frictional and acceleration terms are higher than the decrease in the pressure drop from gravitational term.

$$\frac{dp}{dz} = \frac{g}{g_c}\bar{\rho} + \frac{2f\bar{\rho}u_m^2}{g_c D} + \bar{\rho}\frac{\Delta(u_m^2/2g_c)}{\Delta z} \quad \text{................................(4-9)}$$

Therefore, the results from this high production case ***will not be used*** to evaluate the economic values.

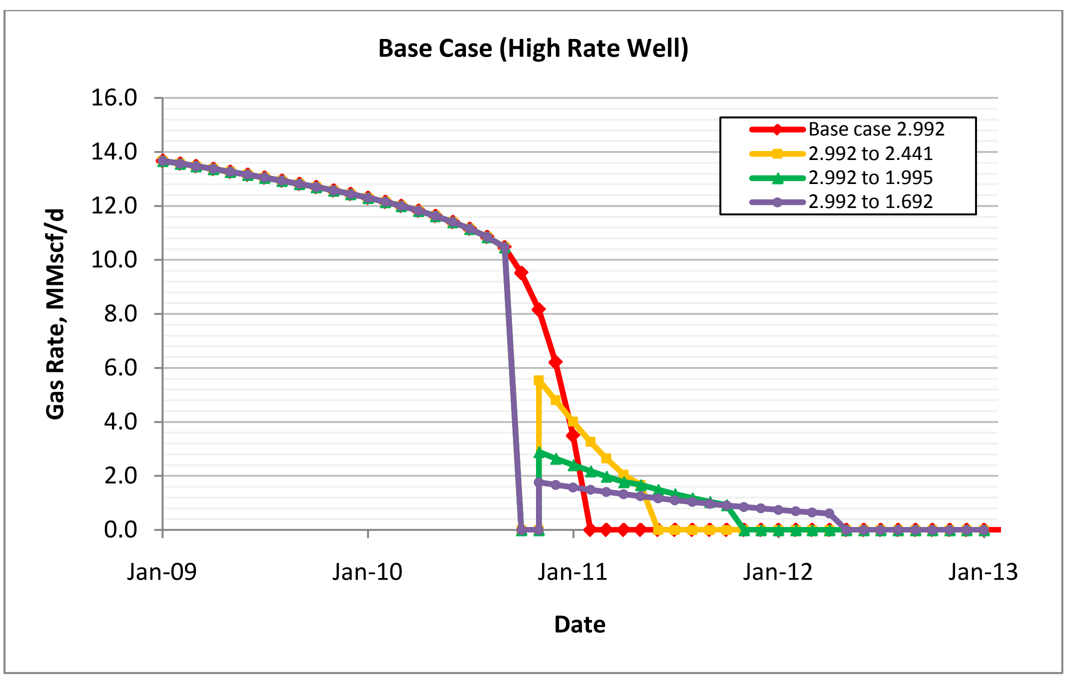

Fig. 4.9— Gas production rate of base case and sensitivity cases for velocity string simulation of high production well.

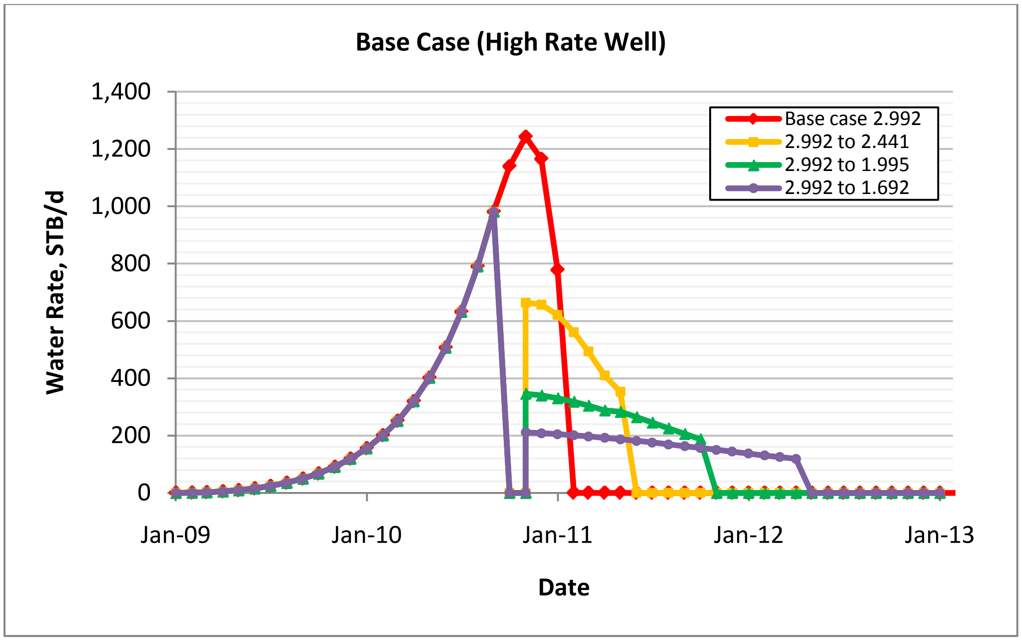

Fig. 4.10— Water production rate of base case and sensitivity cases for velocity string simulation of high production well.

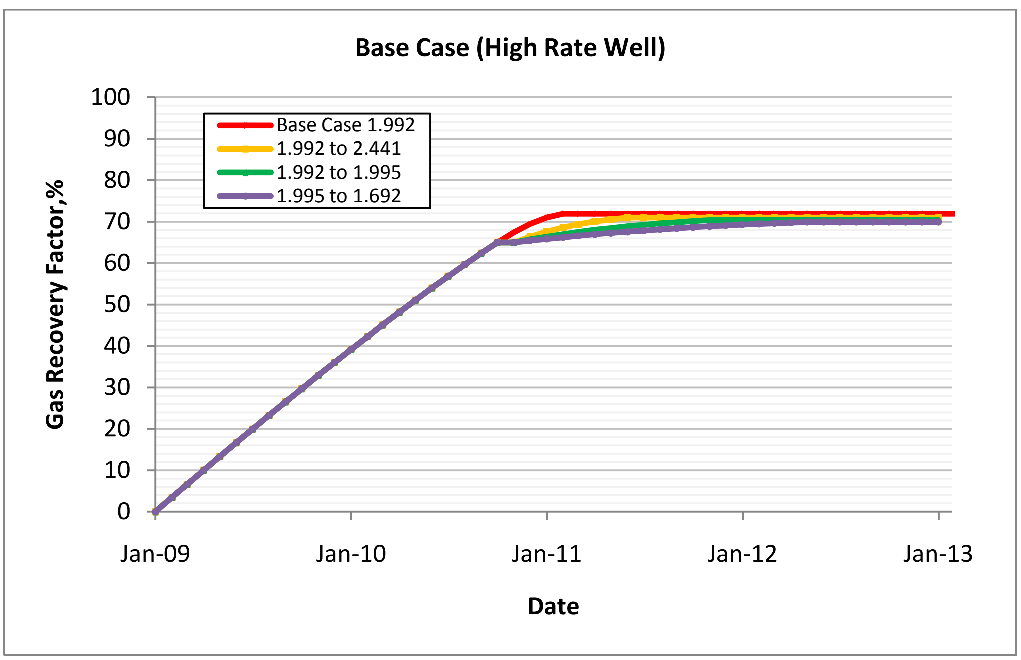

Fig. 4.11— Gas recovery factor of base case and sensitivity cases for velocity string simulation of high production well.

4.4 Gas Lift

Because the simulation program cannot directly model the artificial lifts for gas wells, as recommended by Petroleum Expert, the GAP model for simulating gas lift in gas wells are built by adding the gas source between the inflow and the out flow as shown in Fig. 4.12.

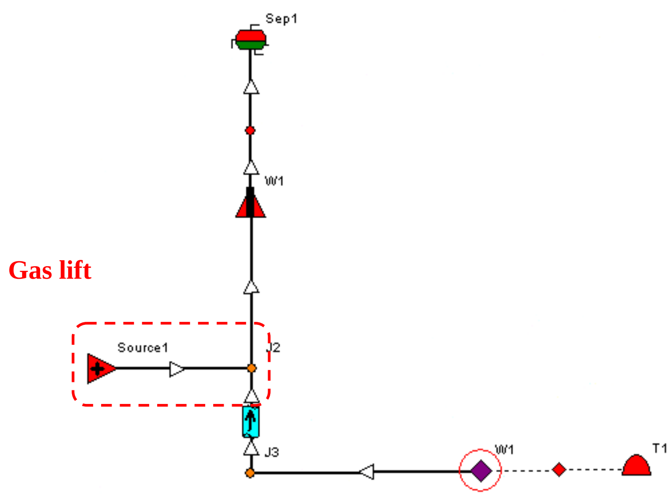

Fig. 4.12— GAP model simulates the gas lift system in gas well.

The sensitivities to determine the optimum gas injection rate are performed. All cases inject gas at day just before the gas rate is below the critical gas rate. The sensitivity can be divided into two sections, low and high production well.

4.4.1 Low Production Rate Well

The sensitivity cases consist of 2.70, 1.72, 1.50, 1.00, 0.50 MMscf/d gas injection (The critical gas rate for the 2.992" tubing is 1.72 MMscf/d). Fig. 4.13 and Fig. 4.14 show the gas and water rates for the base case and the sensitivity case. From those figures, the gas injection helps the well to produce more gas and extend the well life. The amount of the incremental gas production and timing depend on case by case. We cannot judge the optimum gas injection at this moment because we don't know if the injected gas is traded off by the incremental gas production and time until the economic evaluation is performed (in the next Chapter). The gas recovery factors of all cases are shown in Fig. 4.15.

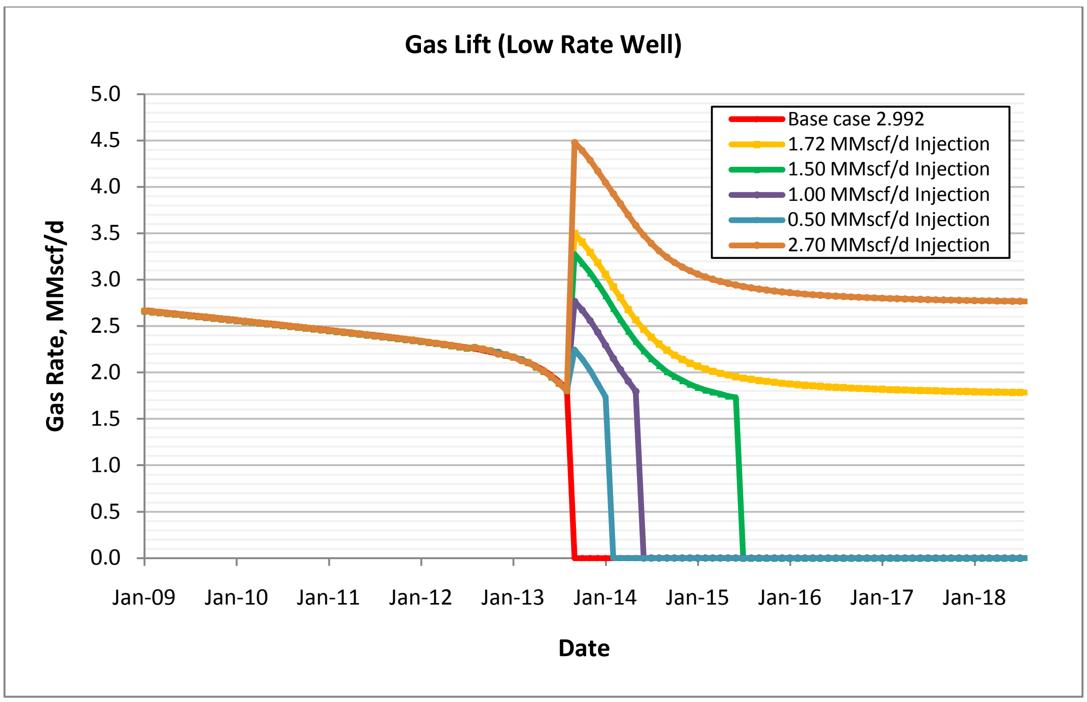

Fig. 4.13— Gas production rate of base case and sensitivity cases for gas lift simulation of low production well.

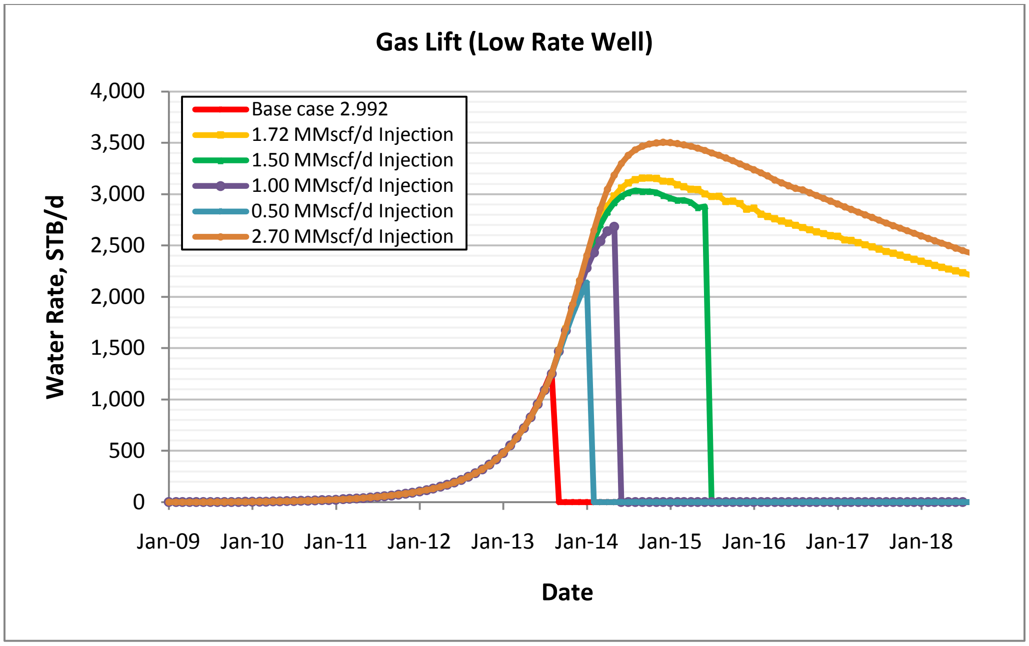

Fig. 4.14— Water production rate of base case and sensitivity cases for gas lift simulation of low production well.

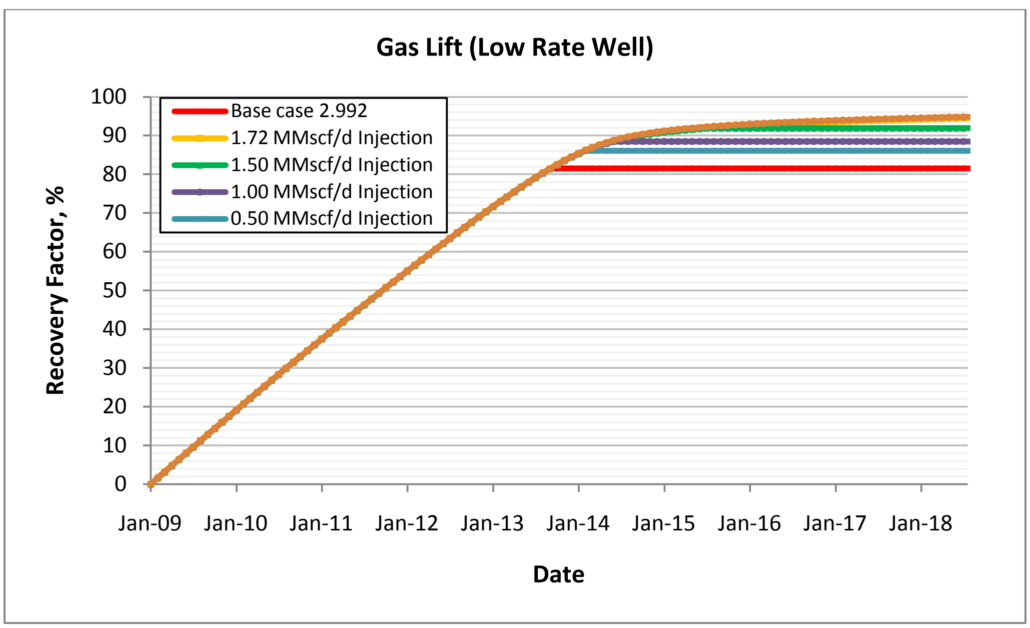

Fig. 4.15— Gas recovery factor of base case and sensitivity cases for gas lift simulation of low production well.

4.4.2 High Production Rate Well

We used the same basis of the low rate case but increase the injection rate to 7.00, 5.00, 3.00, 1.72, 1.00 MMscf/d. The critical gas rate for the 2.992" tubing is 1.72 MMscf/d. Fig. 4.16 and Fig. 4.17 show the gas and water rates for the base case and the sensitivity case. From those figures, the gas injection helps the well to produce more gas and extend the well life. We run gas injection for 20 years. The amount of the incremental gas production and timing depend on case by case. We cannot judge the optimum gas injection at this moment because we don't know if the injected gas is traded off by the incremental gas production and time until the economic evaluation is performed (in the next Chapter). The gas recovery factors of all cases are shown in Fig. 4.18.

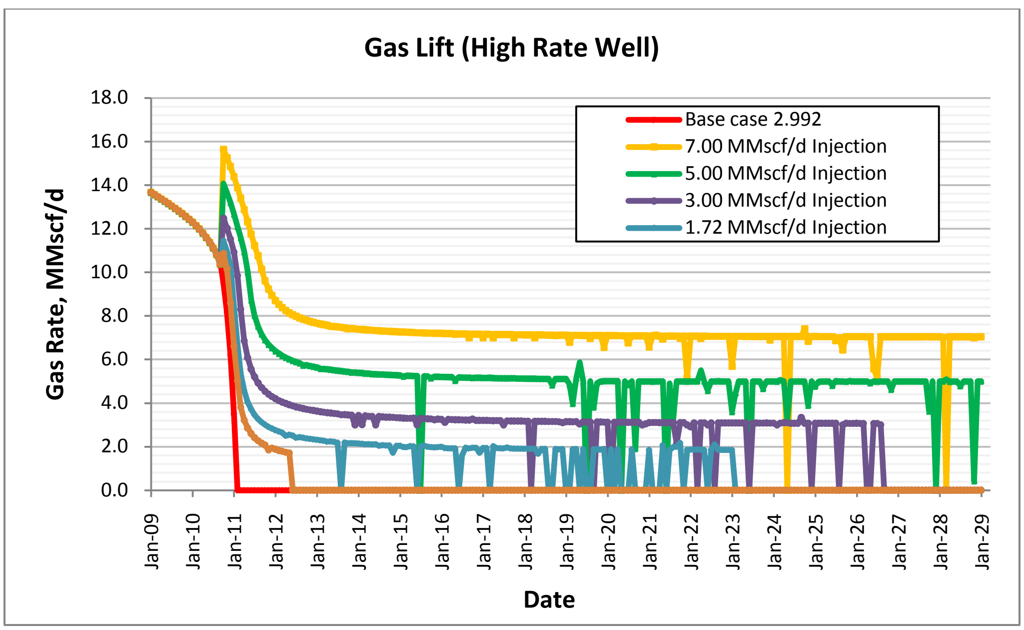

Fig. 4.16— Gas production rate of base case and sensitivity cases for gas lift simulation of high production well.

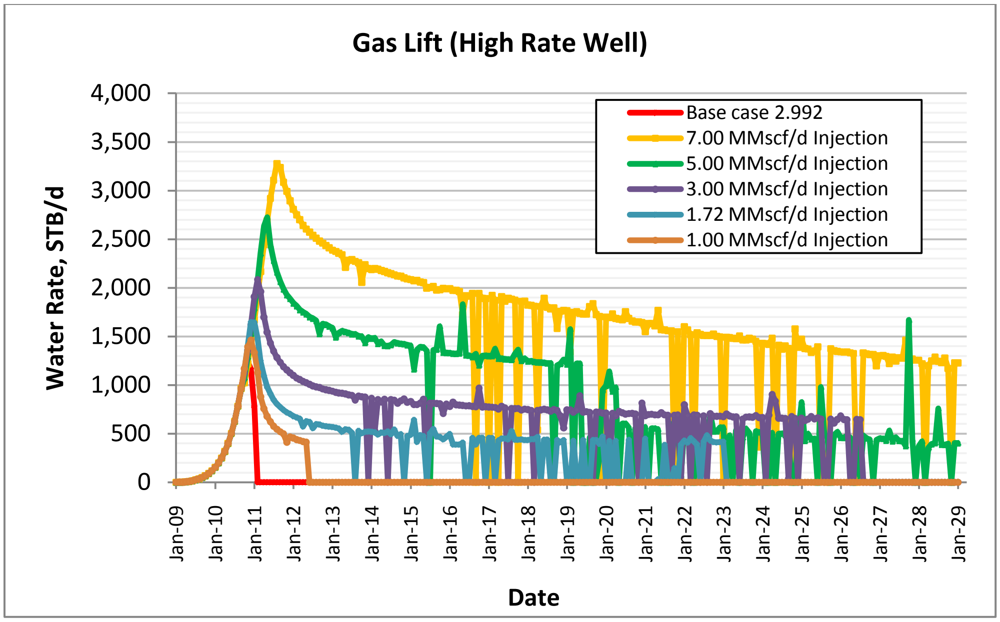

Fig. 4.17— Water production rate of base case and sensitivity cases for gas lift simulation of high production well.

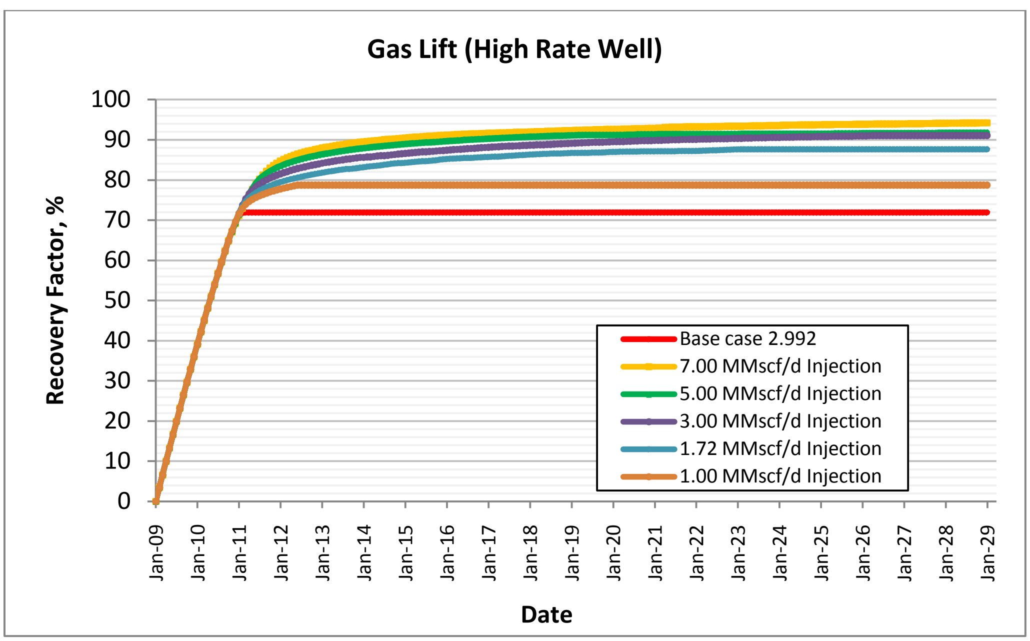

Fig. 4.18— Gas recovery factor of base case and sensitivity cases for gas lift simulation of low production well.

4.5 Electrical Submersible Pump (ESP)

There are two ways to install ESP. The first one is ESP that has the inline separation to separate gas to flow in the annulus and let liquid flow through the pump. This ESP can go above the perforation but can boost the pressure only for liquid. Because there is no artificial lift option for gas well in Petroleum Expert Package, we have to find other ways to simulate ESP behavior in gas well. For this type of pump, we used the “pump” option in GAP to simulate ESP as shown in Fig. 4.19 (as suggested by Petroleum Expert). However, in this option, the “pump” converted all the mass (gas and liquid) to the equivalent liquid volume and lifted everything up to surface. This was not what we tried to simulate ESP behavior that only water should be pumped. Then we tried an option to separate 100% gas before the “pump”. However, again, the well produces only water now and not produces any gas. *Therefore, this option is not applicable.*

The second way is ESP without the inline separation. This type of ESP has to be submerged in the liquid and below the perforation. It can boost the pressure for both gas and liquid through the tubing which works the same way as the downhole multiphase pump (downhole MPP). For this type of pump, we use “inline element” to simulate ESP as shown in Fig. 4.20. The “inline element” is a tool that added into the system to do the function we want by writing the script in it. The script that we write adds additional pressure in to the system but still the constant flow rate. We write the equation to calculate additional pressure (Δp) from ESP by using the pump performance curve, which is the relationship between the pressure and the water flow rate.

The outlet pressure of the pump is the result from the inlet pressure of the pump plus the additional pressure gain from the pump, which is from the pump performance curve. The pump performance curve is chosen by determining the range of the water production rate that we have. The pump chart for 1-stage ESP that corresponds to this rate is selected as shown in Fig. 4.21.

From the behavior of this type of pump that needs to be submerge in the water all the time, we assume the pump is not active until the water rate reaches 500 STB/d. and the well dies when the gas rate reach the critical rate of 1.72 MMscf/d.

In this simulation, the script is written for 50-stages ESP in the “inline element”. The script for the additional pressure of the “inline element” is shown as the following.

$$\begin{aligned}\mathrm{DeltaPressure}\\ &= -0.000000000038597 * \mathrm{pow}(\mathrm{QWATIN}, 4) + 0.000000108603263\\ &* \mathrm{pow}(\mathrm{QWATIN}, 3) - 0.000114003146853 * \mathrm{pow}(\mathrm{QWATIN}, 2)\\ &- 0.035780536131199 * \mathrm{QWATIN} + 627.516923077201000\end{aligned}$$

For all reasons mentioned above, the model that can represent the pump system was built by using the “inline general element”.

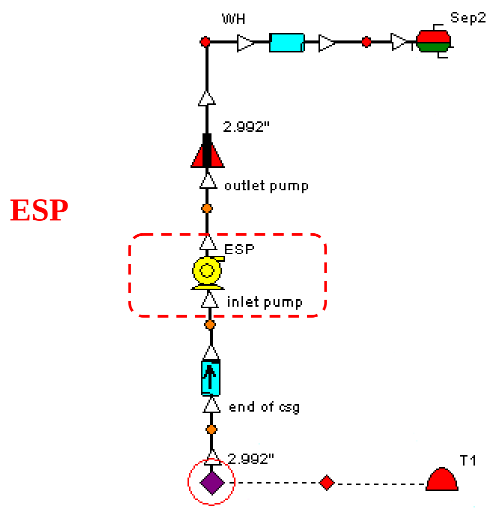

Fig. 4.19— GAP model simulates the pump system in gas well using "pump".

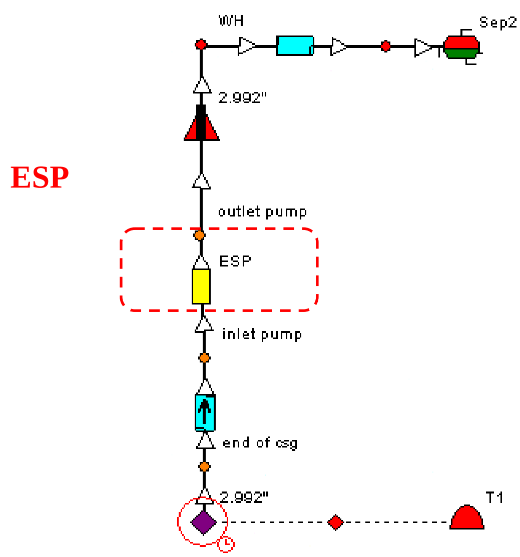

Fig. 4.20— GAP model simulates the pump system in gas well using "inline element".

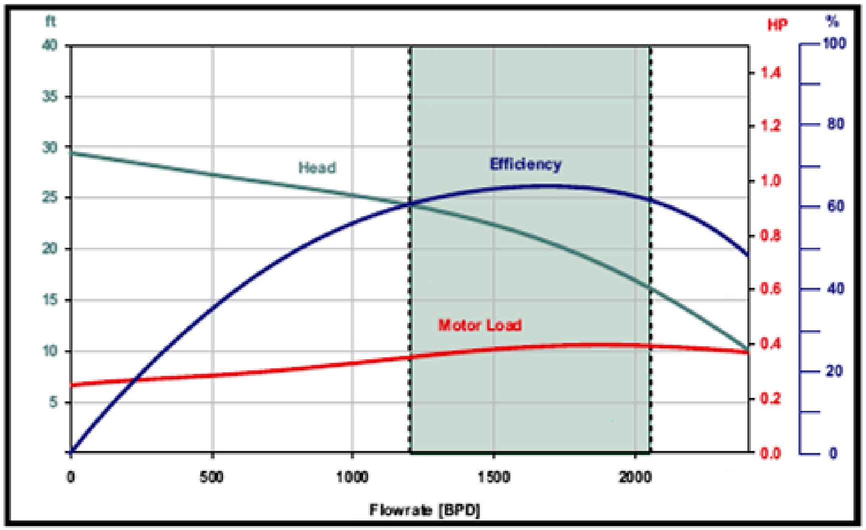

Fig. 4.21— Pump performance curve for pump 400-1750a, 60 Hz (Weatherford 2006)).

The two cases, low production and high production well, to determine the effect of the ESP are performed. The ESP starts when the water rate reach 500 STB/D as discussed before. The 1-month downtime for ESP installation is applied to the profile before ESP starting. The gas production ends when the gas rate reaches the critical rate (1.72 MMscf/d).

4.5.1 Low Production Rate Well

The results from pump simulation are shown in Fig. 4.22, Fig. 4.23, and Fig. 4.24. The pump helps the well by adding the additional pressure at the bottomhole resulting to the additional gas production rate for 8 months. After that, the well dies because of the water loading (the gas flow rate is below the critical flow rate of 1.72 MMscf/d). The recovery factor when adding ESP to the well increases from 81.5% (base case) to 83.3%.

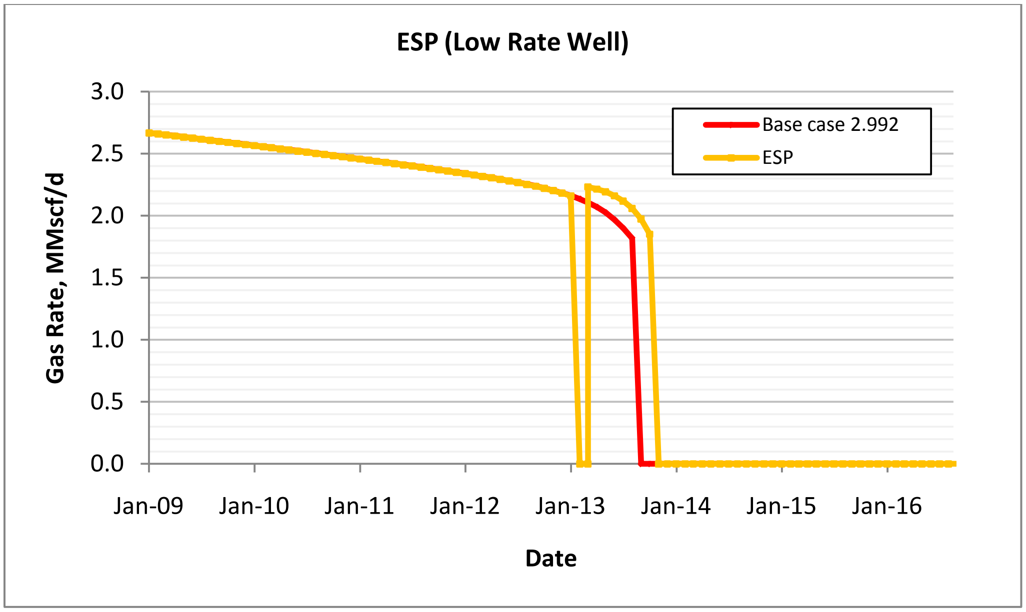

Fig. 4.22— Gas production rate of base case and ESP simulation case of low production well.

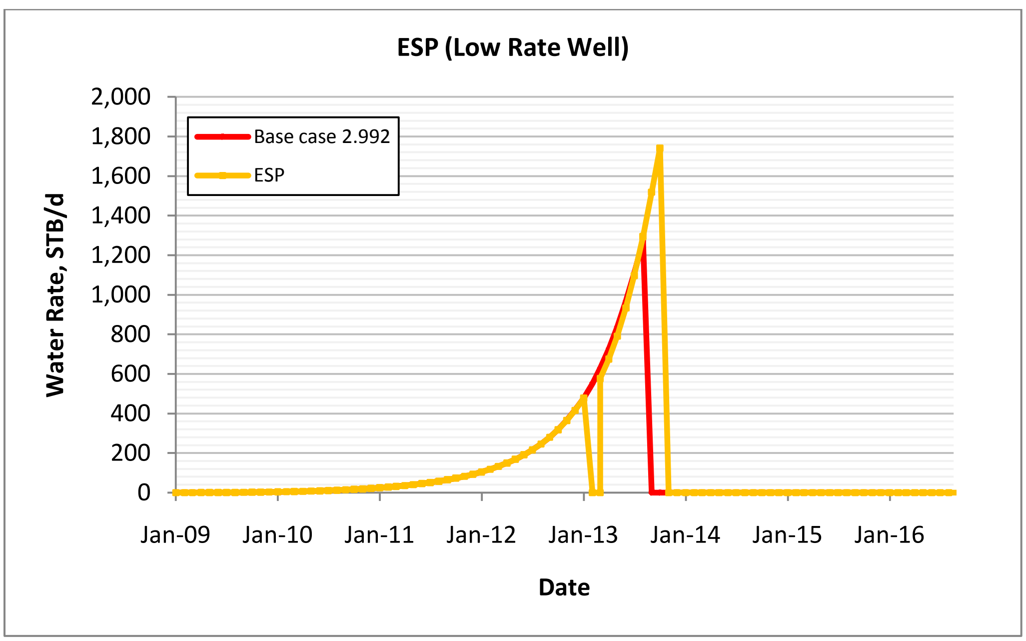

Fig. 4.23— Water production rate of base case and ESP simulation case of low production well.

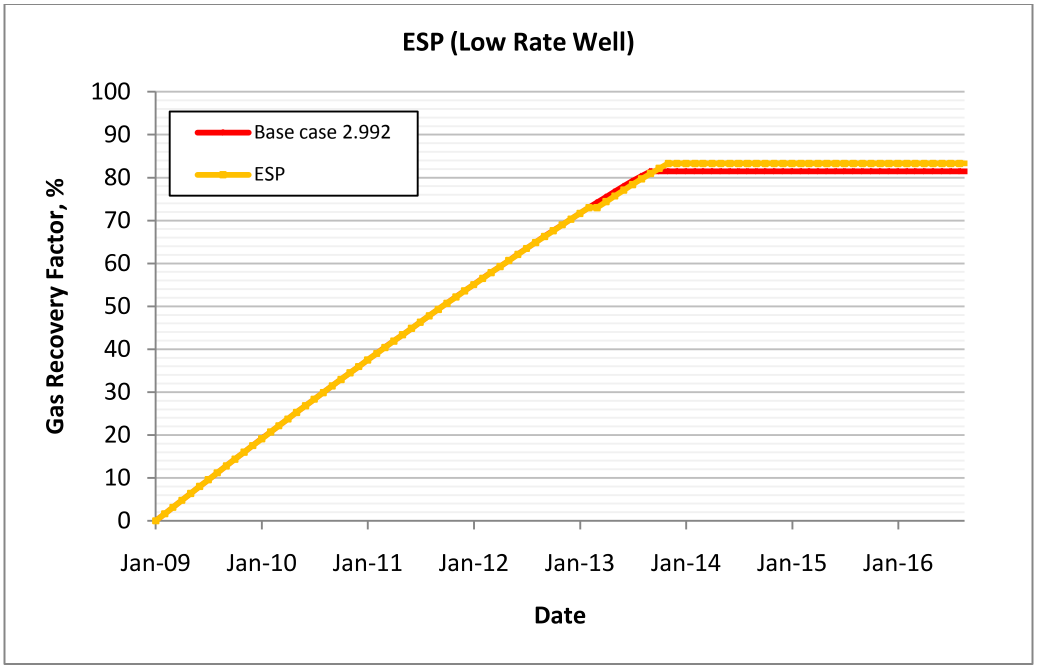

Fig. 4.24— Gas recovery factor of base case and ESP simulation case of low production well.

4.5.2 High Production Rate Well

The results from pump simulation are shown in Fig. 4.25, Fig. 4.26, and Fig. 4.27. The results are in the same trend of the low rate well case. The pump helps the well by adding the additional pressure at the bottomhole resulting to the additional gas production rate for 8 months. After that, the well dies because of the water loading (the gas flow rate is below the critical flow rate of 1.72 MMscf/d). The recovery factor when adding ESP to the well increases from 71.8% (base case) to 74.5%.

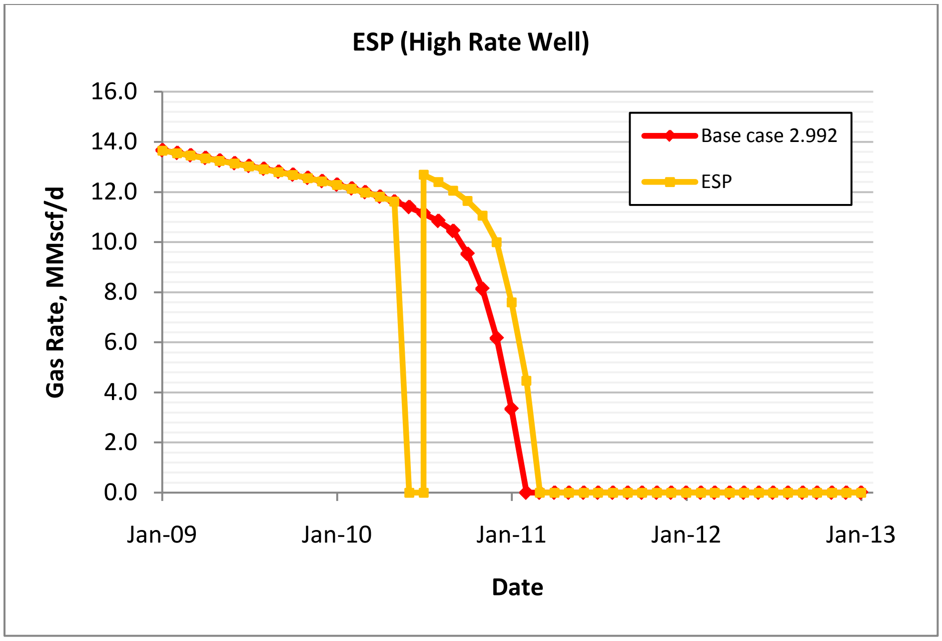

Fig. 4.25— Gas production rate of base case and ESP simulation case of high production well.

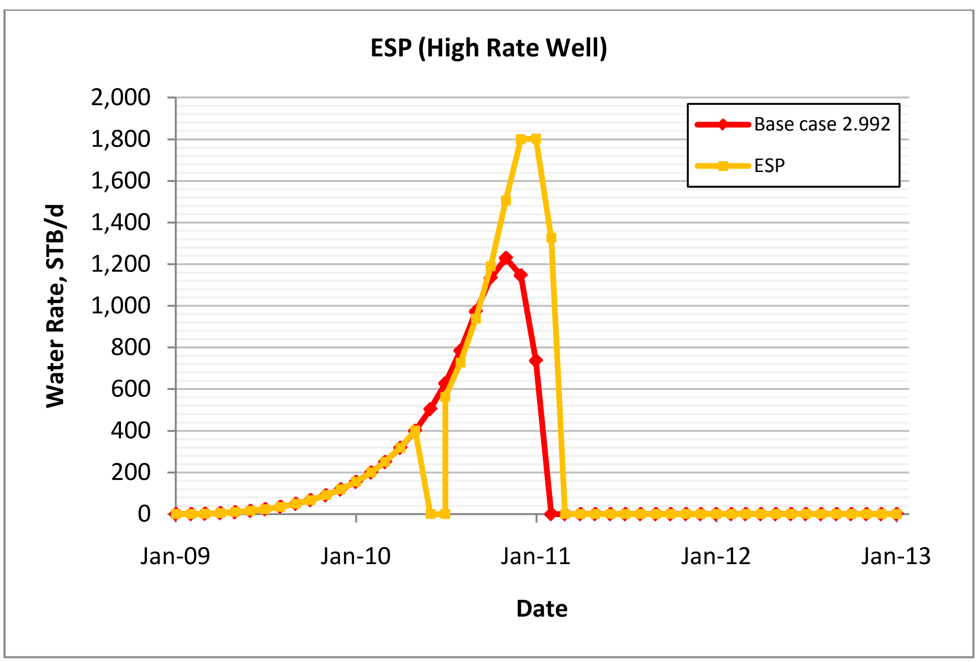

Fig. 4.26— Water production rate of base case and ESP simulation case of high production well.

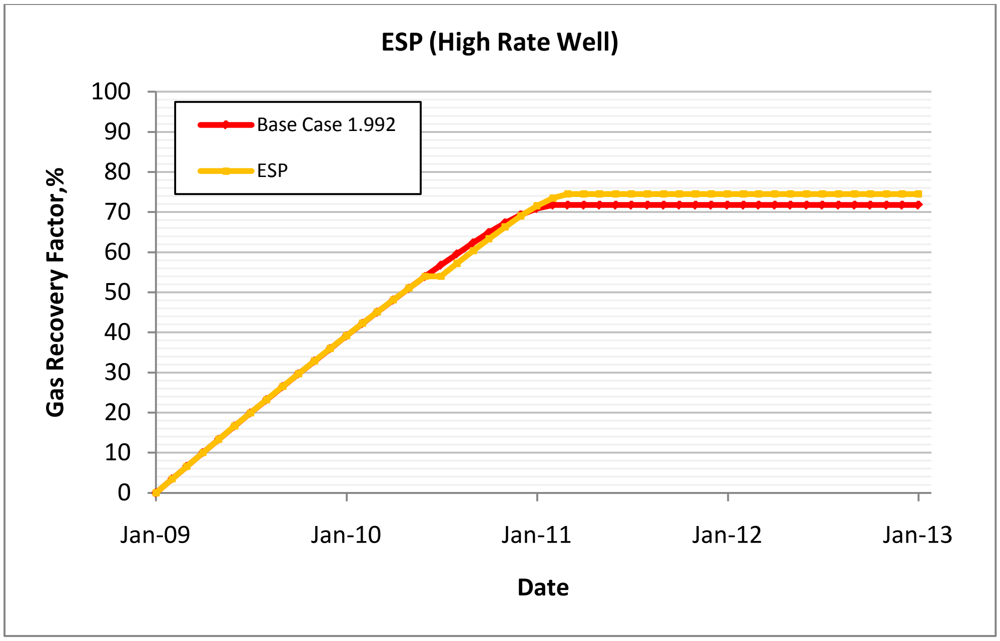

Fig. 4.27— Gas recovery factor of base case and ESP simulation case of high production well.

CHAPTER V

ECONOMIC EVALUATION

This Chapter talks about the economic evaluation part for the decision matrix. We updated all the cost for the previous seven artificial lift methods. We added the cost for three additional methods, which are the velocity string, foam injection, and heated tubing.

We also calculated and compared the economic values, which are the net present value (NPV) and the internal rate of return (IRR) for three artificial lift methods, which are gas lift, velocity string, and ESP.

The net present value (NPV) is the sum of the present values (PVs) of the individual cash flows. In case when all future cash flows are incoming and the only outflow of cash is the purchase price, the NPV is simply the PV of future cash flows minus the purchase price (which is its own PV). NPV is a central tool in discounted cash flow (DCF) analysis, and is a standard method for using the time value of money to appraise long-term projects.

The net present value (NPV) is the present value of an investment's future net cash flows minus the initial investment. If positive, the investment should be made (unless an even better investment exists), otherwise it should not. Table 5.1 shows the decisions for three cases of NVP values.

Table 5.1— Consequence of NPV to the Project Decision.

If...	It means...	Then...
NPV > 0	the investment would add value to the firm	the project may be accepted
NPV < 0	the investment would subtract value from the firm	the project should be rejected
NPV = 0	the investment would neither gain nor lose value for the firm	We should be indifferent in the decision whether to accept or reject the project. This project adds no monetary value. Decision should be based on other criteria, e.g. strategic positioning or other factors not explicitly included in the calculation.

The formula to calculate NPV is shown in Eq.5-1 (Lake and Fanchi 2006).

$$PV = FV\left[\frac{1}{(1+i_e)^n}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5\text{-}1)$$

where PV is the present value

FV is the future value

i_e is the effective rate

n is the number of period

The internal rate of return (IRR) is defined as any discount rate that results in a net present value of zero in a series of cash flows. It is the interest rate received for an investment consisting of payments (negative values) and income (positive values) that occur at regular periods. If C(n) is the cash flow for each period, then

$$NPV = C(0) + C(1)/(1+r) + C(2)/(1+r)^2 + \ldots + C(n)/(1+r)^n \ldots (5\text{-}2)$$

You would find IRR by setting NPV = 0 and solving for “r” above. (Excel’s IRR function makes this all a cinch by running iterations.)

At this moment, we want to show the new workflow of the decision matrix, which including the production simulation and the full cycle of economic analysis (NPV and IRR calculations) for three methods, which are the velocity string, gas lift, ESP because of the limit timeframe. The further simulation for other artificial lift methods can be done in the future to complete the decision matrix.

To determine the additional money that we gain from the artificial lift methods, we need to compare the artificial lift methods with the base case. We assume that the base OPEX (i.e. the cost to normally run the well) have been ignored as they would be the same for all cases (base case and the artificial lift cases).

The following are the detailed economic evaluations for the artificial lift methods.

5.1 Velocity String

From the production profiles mentioned in Chapter IV, only the low rate gas well can get the additional gas production from the velocity string. We do not gain any additional gas production from the velocity string for the high rate case. Therefore, only low rate case is determined here.

The optimum production case for the low rate gas well that give the maximum gas production is the case that changes the tubing ID of 2.992” to 1.692”. We use this case to calculate for the economic values.

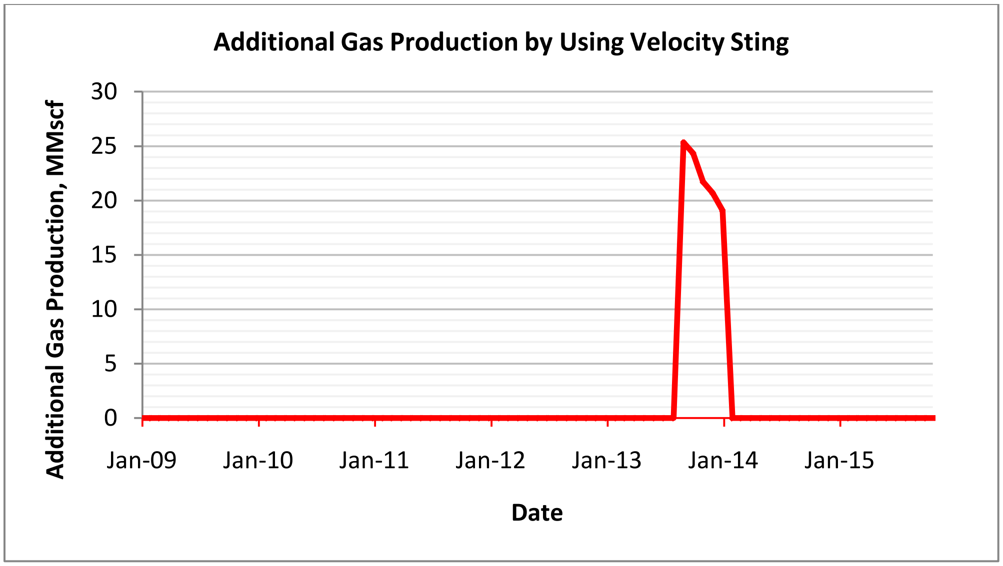

Fig. 5.1— Additional gas production of the case using 1.692” velocity string.

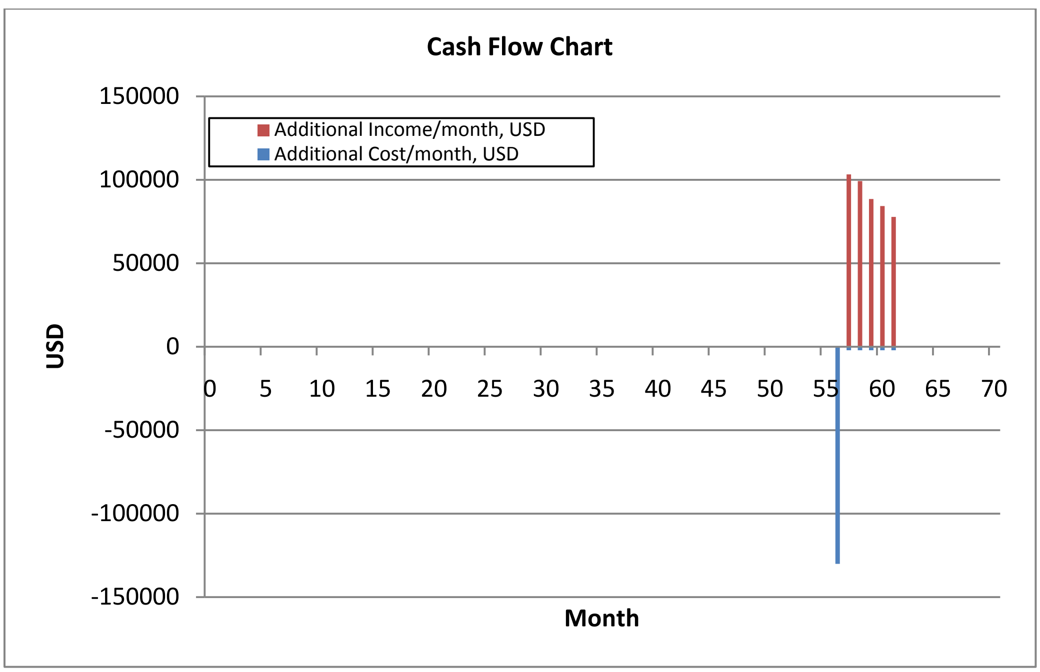

Fig. 5.2— Cash flow chart of the case using 1.692” velocity string.

Fig. 5.1 shows the additional gas production profile when changing the tubing from 2.992” (base case) 1.692” ID. We switched the tubing just before the well reach the maximum water production. In this particular case, it is in August 2013. After that the well can produce five more months before reaching the critical rate and die. The amount of the extra gas production that is from tubing 1.692” ID is used in the economic calculation.

The initial cost, the operating and maintenance costs per year are determined to be the expenditure of this case. The income of this case is from the sale gas from the additional gas production by assuming the gas price of $4/MMBTU. The profit is equal to the difference between the income and outcome. Fig. 5.2 shows the cash flow chart of this case. In the month of 56, we change the producing string from 2.992” to 1.692”. Therefore, the down time of the production has to be added to the profile in the month of 56. Then we start production in the month of 57 and receive the income from the sale gas.

NPV is calculated from the cash flow. By assuming 10% interest rate per year, NPV of this case is about $194653. IRR is equal to 5147%.

The result shows very high IRR. The reason is that the CAPEX is small and the OPEX is really small comparing to the income we get in each month. Therefore, we have a lot of profit in every month. We need a large discount rate (r in Eq.5-2) to discount the large amount of profit in each month to get the summation of the present value (NPV) to be equal to zero (IRR definition).

$$NPV = C(0) + C(1)/(1+r) + C(2)/(1+r)^2 + \ldots + C(n)/(1+r)^n \ldots \text{(5-2)}$$

5.2 Gas Lift

5.2.1 Low Production Rate Well

From Chapter IV, we have the production profile for all sensitivity cases, which are 2.70, 1.72, 1.50, 1.00, 0.50 MMscf/d gas injection. We can now determine the optimal gas injection rate by using economic to be a cutoff. Fig. 5.3 shows the additional gas production gains from each gas injection rate.

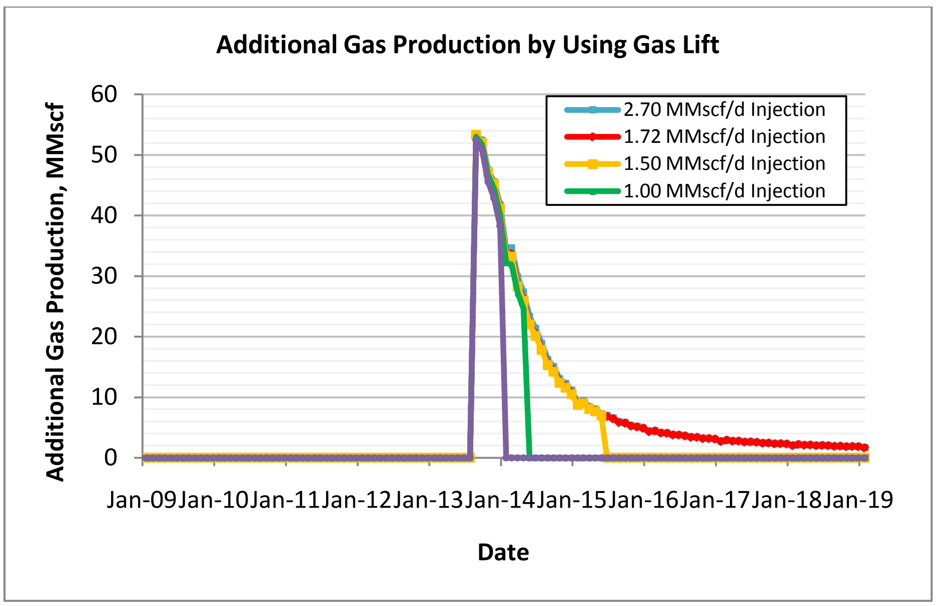

Fig. 5.3— Additional gas production of the case using gas lift for 1.72, 1.50, 1.00, 0.50 MMscf/d injection rate.

From the economic calculation by assuming the gas price of $4/MMBTU, the 2.70, 1.72, 1.50, 1.00, 0.50 MMscf/d injection cases have the NPV of -$915692, -$455902, -$533907, -$856561, and -$816998, respectively (using 10% interest rate). All NPV are negative. The IRR for the 2.70, 1.72, 1.50, 1.00, 0.50 MMscf/d injection cases are 1, 5, 3, -4, and -8%, respectively. The cause for negative NPV is that the CAPEX for installation of gas lift is really high compared to the additional gas production gained and we need to install the injection system since year 0 (the most impact to time value of money). From these results, none of the sensitivity cases is interesting for investment.

To illustrate the example steps of NPV calculation, Fig. 5.4 shows the cash flow chart of the 1.72 MMscf/d injection case (The highest IRR case). We have the capital expenditure (CAPEX), which is the installation cost, at year 0. We start injection after 57 months. Therefore, we need to buy a amount of gas for gas injection (gas cycling) at the month of 56. We assume that we buy two times of the amount to take into account for the lagging of the cycling time. There are the maintenance costs, fuel, costs in every month after starting injection. The income comes from the sale gas from the additional gas production gain from 1.72 MMscf/d gas injection. In the last month of the production when the profit is going to be negative (cost is larger than income), we sell the cycling injection gas.

Note that the case of 1.72 MMscf/d gas injection rate may not have the additional gas production as shown in the results because the Turner cut-off rate used (1.72 MMscf/d) is not realistic. As discussed before, we do not believe that Turner cut-off is correct. If the actual critical rate is higher than Turner cut-off, the additional gas production will be smaller.

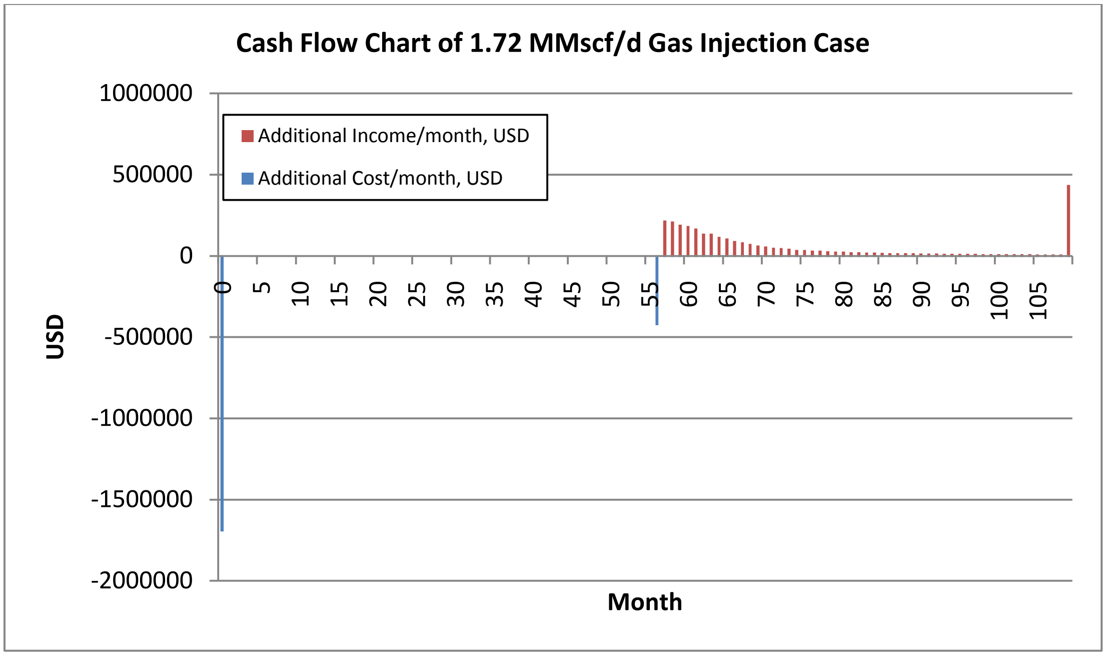

Fig. 5.4— Cash flow chart of the case using gas lift (1.72 MMscf/d gas injection).

5.2.2 High Production Rate Well

Fig. 5.5 shows the additional gas production gains from gas injection rate of 7.00, 5.00, 3.00, 1.72, and 1.00 MMscf/d.

From the economic calculation by assuming the gas price of $4/MMBTU, the 7.00, 5.00, 3.00, 1.72, and 1.00 MMscf/d injection cases have the NPV of $3075958, $3219974, $3334507, $3260130, and $2058193, respectively (using 10% interest rate). The highest NPV is from 3.00 MMscf/d injection case. The IRR for this case is 47%. Fig. 5.6 shows the cash flow chart of the 3.00 MMscf/d injection case. We have the capital expenditure (CAPEX), which is the installation cost, at year 0. We start injection after 21 months. Therefore, we need to buy an amount of gas for gas injection (gas cycling) at the month of 20. We assume that we buy two times of the amount to take into account for the lagging of the cycling time. There are the maintenance, fuel, costs in every month after starting injection. The income comes from the sale gas from the additional gas production gained from 3.00 MMscf/d gas injection. In the last month of the production when the profit is going to be negative (cost is larger than income), we sell the cycling injection gas.

The high CAPEX cost has high impact to the cash flow because it is a big amount of money that we have to spend at time 0 (the most effect from time value of money).

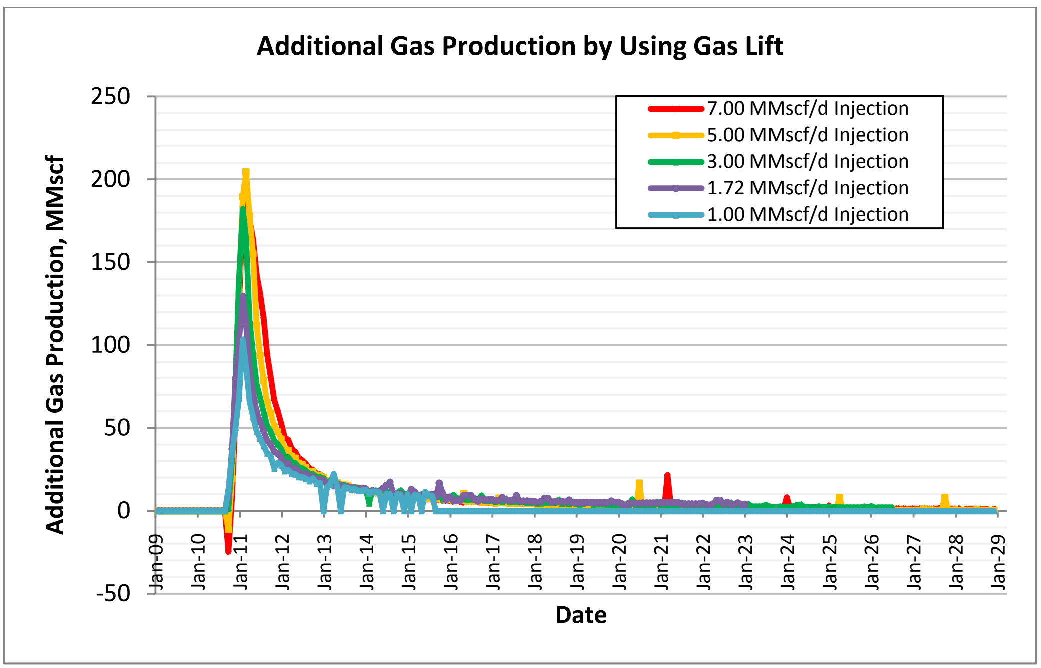

Fig. 5.5— Additional gas production of the case using gas lift for 7.00, 5.00, 3.00, 1.72, 1.00 MMscf/d injection rate.

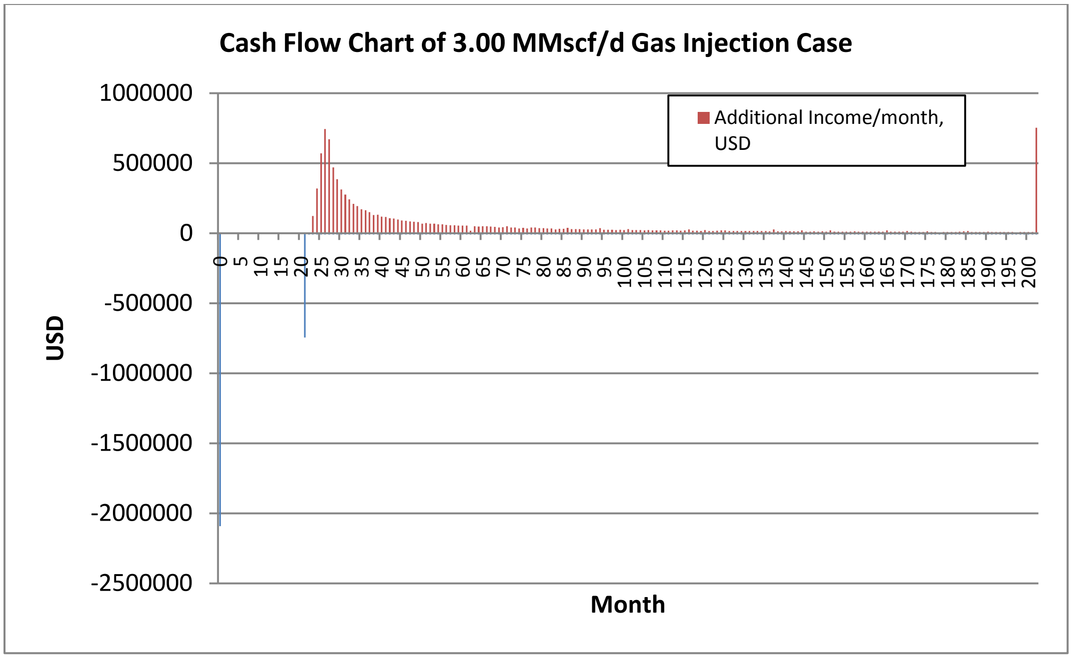

Fig. 5.6— Cash flow chart of the case using gas lift (3.00 MMscf/d gas injection).

5.3 Electrical Submersible Pump (ESP)

As seen in Chapter IV, we get the additional gas production from ESP in both cases, low rate and high rate wells. For the economic evaluation, we assume that we have 1-month downtime for ESP installation before starting ESP. ESP starts when the water reaches 500 STB/d as discussed in Chapter IV. The following are the results for the low rate and high rate wells.

5.3.1 Low Production Rate Well

Fig. 5.7 shows the additional gas production profile when adding ESP in the system. As a result, the well can produce eight more months before reaching the critical rate and die. The amount of the extra gas production that is from adding ESP is used in the economic calculation.

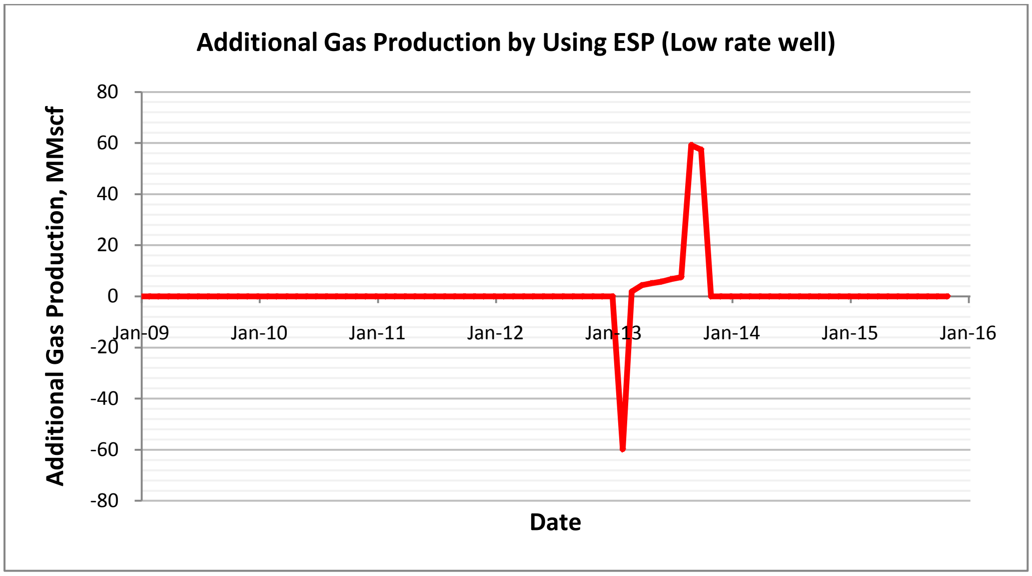

Fig. 5.7— Additional gas production of the ESP (low rate case).

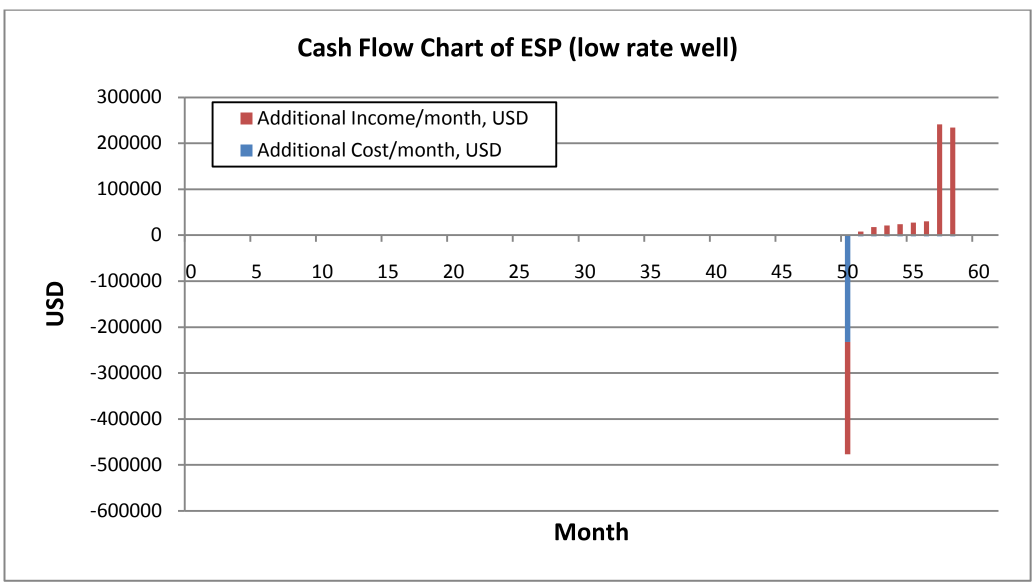

Fig. 5.8— Cash flow chart of the ESP (low rate well).

Fig. 5.8 shows the cash flow chart of this case. We have the installation cost for ESP at the month of 50. We also have the loss of the gas production due to the 1-monnth downtime for ESP installation. After ESP is online, we can produce eight more months. We have the operating cost while we producing gas. The income of this case is from the sale gas from the additional gas production.

NPV is calculated from the cash flow. By assuming the gas price of $4/MMBTU and 10% interest rate per year, NPV of this case is $49794. IRR is equal to 41.9%.

5.3.2 High Production Rate Well

Fig. 5.9 shows the additional gas production profile when adding ESP in the system. As a result, the well can produce eight more months before reaching the critical rate and die. The amount of the extra gas production that is from adding ESP is used in the economic calculation.

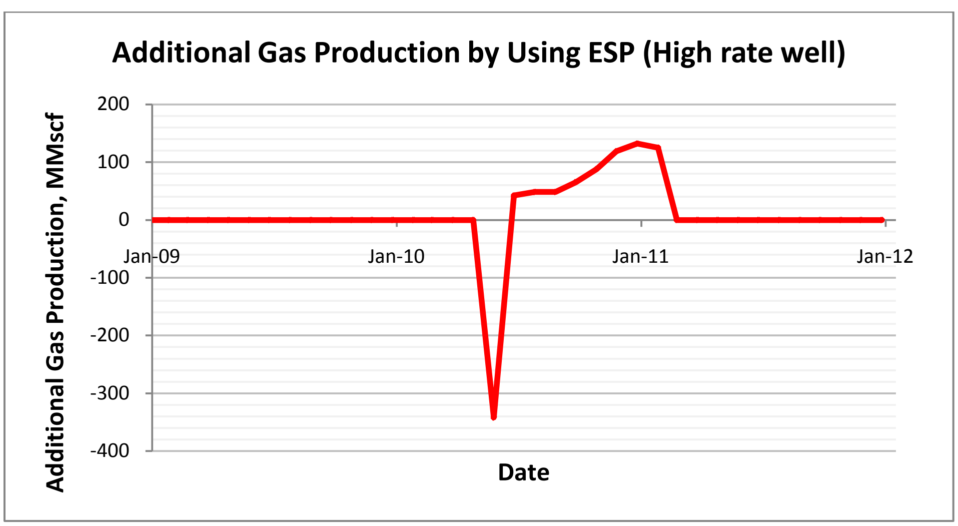

Fig. 5.9— Additional gas production of the ESP (high rate case).

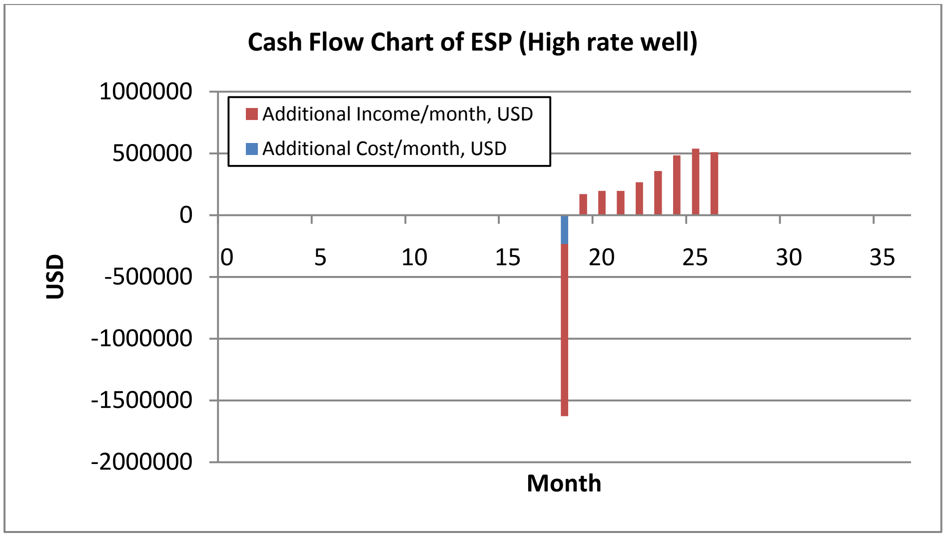

Fig. 5.10— Cash flow chart of the ESP (high rate well).

Fig. 5.10 shows the cash flow chart of this case. We have the installation cost for ESP at the month of 18. We also have the loss of the gas production due to the 1-monnth downtime for ESP installation. After ESP is online, we can produce eight more months. We have the operating cost while we producing gas. The income of this case is from the sale gas from the additional gas production.

NPV is calculated from the cash flow. By assuming the gas price of $4/MMBTU and 10% interest rate per year, NPV of this case is $833768. IRR is equal to 222.4%.

The reason for high IRR is the same as in the velocity string case that the CAPEX and OPEX are small comparing to the income we get. Therefore we need high discount rate to discount the profit and make the discounted profit summation equal to zero (IRR definition).

CHAPTER VI

CONCLUSION, DISCUSSION, AND FUTURE WORK

6.1 Conclusion

The following are the conclusions of what we have done.

- Extended a work flow of the decision matrix that is the full cycle of evaluation starting from the preliminary screening, technical evaluation, production simulation, and economic evaluation.
- Added three production simulations, which are velocity string, gas lift, and ESP.
- Performed economic analysis for NVP and IRR of three artificial lift methods that have production profiles for base, low rate, and high rate cases.
- Developed a new decision matrix tool that uses a decision tree method to screen the best artificial lift method for the liquid loading in gas wells with
    - Three additional artificial lift methods
    - Updated screening criteria
    - Updated technical evaluation
    - Updated cost

We hope that by using this new workflow and the updated decision matrix, we can determine the best artificial lift methods for the liquid loading problem in gas wells and save operators time and money they would otherwise spend trying many artificial lift methods by themselves.

6.2 Discussion

- Because Petroleum Expert packages for integrated reservoir-wellbore modeling (GAP, MBAL, and PROSPER) are limited simulating the artificial lift only in oil wells, it is not easy to simulate artificial lift to solve the liquid loading problem in gas wells. Due to the limit timeframe, we only performed the simulations for three methods, which are the velocity string, gas lifts, and ESP. Therefore, the more artificial lift simulations should be performed in the future.
- The simulation cases we have performed are only a few possibilities of the real cases. They may not be exactly the same conditions as the operators have. Therefore, a fine-tune simulation has to be done case by case to represent real conditions.
- Turner critical rate itself is also not practical because it does not change with the flow regime, well depth, reservoir condition (permeability, thickness), or production condition (WGR). As discussed before, it depends only on liquid surface tension, gas density, water density, gas compressibility factor, pressure at surface, temperature at surface, and tubing cross-sectional area. Therefore, for two wells with different flow regime, well depth, reservoir properties (permeability, thickness) and different production parameters (WGR), we still have the same Turner velocity and critical rate, which does not make sense.
- We use the average Turner critical rate from PROSPER to be a cut-off and manually use this cut-off in GAP. This is not exactly correct because GAP

should link with PROSPER and check for Turner critical rate in every time step, not using only one fixed average Turner cut-off.

- We assume that when the gas rate is below the cut-off, the well dies, which is not realistic. In real production cases, when the liquid loading starts, the gas production rate drops rapidly but the well is still flowing for some times before the well dies.

6.3 Future Work

The following are the future work to make the matrix more complete.

- Perform more possibility cases for the three methods that have been simulated.
- Perform more simulation for other lift methods and apply them to the decision matrix.
- Continue adding the new technology for liquid unloading technique to the decision matrix codes.
- Continue considering more factors that affecting screening in the decision matrix.
- Keep updating all costs for all lift methods and gas price. There two factors are the keys for the economic evaluation and they change all the time.
- Test and validate the decision matrix with the real field data. In particular, a new field development case would be ideal to test the screening capabilities of the decision matrix.

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APPENDIX I

Artificial Lift Criteria Used For Gas Wells From Chevron

	Rod pump	ESP	Gas Lift	PCP	Plunger lift	Hydraulic Reciprocating Piston Pump	Hydraulic Jet	Cap. String
Operating well depth, ft (TVD)	16000 *4875*	15000 *4572*	18000 *4572*	12000 *3658*	19000 *5971*	17000 *5182*	15000 *4572*	22000 *6705*
Operating volume (min.- max.), BFPD	6000	350-135,000	100-30,000	20-7,500	200	8000	20000	500
Operating temp. 'F (max.)	600	410	400	250	550	550	550	400
Deviation well applicability	Generally operated upto 30-40' ; but known to have installed in 60 degree deviated wells	0-90	0-70	application dependent	Typically near vertical wells; maximum devaition of 60'	0-90	0-90	Typically < 5', max 60'
Casing/ Tubing diameter range, inch	(> 2 3/8") Plunger OD 1 1/2"-5 3/4"	Casing diameter 5.5-13 5/8" MIN	All API casing sizes available	4.5&5.62	< 3 1/2" (though any Tubing size works; it is related to efficiency)	Tubing diameter > 2 3/8"	Insert inside 2 7/8" tbg	any tubing size; but efficiency reduces for large diameters
Gas Handling	Fair to Good	Fair	Excellent	Good	Excellent	Fair	Good	Excellent
Solid handling	Fair to Good	Poor to Fair	Good to excellent	Excellent	Poor to Fair	Fair	Good	Fair to moderate
Offshore application	Limited	Excellent	Excellent	Applicable - Limited by depth	Installed in some locations below SSSV	Excellent	Excellent	Excellent
Installation costs ($000)	234	103	40	53	8	134	134	44
Monthly Operating costs ($)	2800	3987	4180	700	200	3380	3380	400

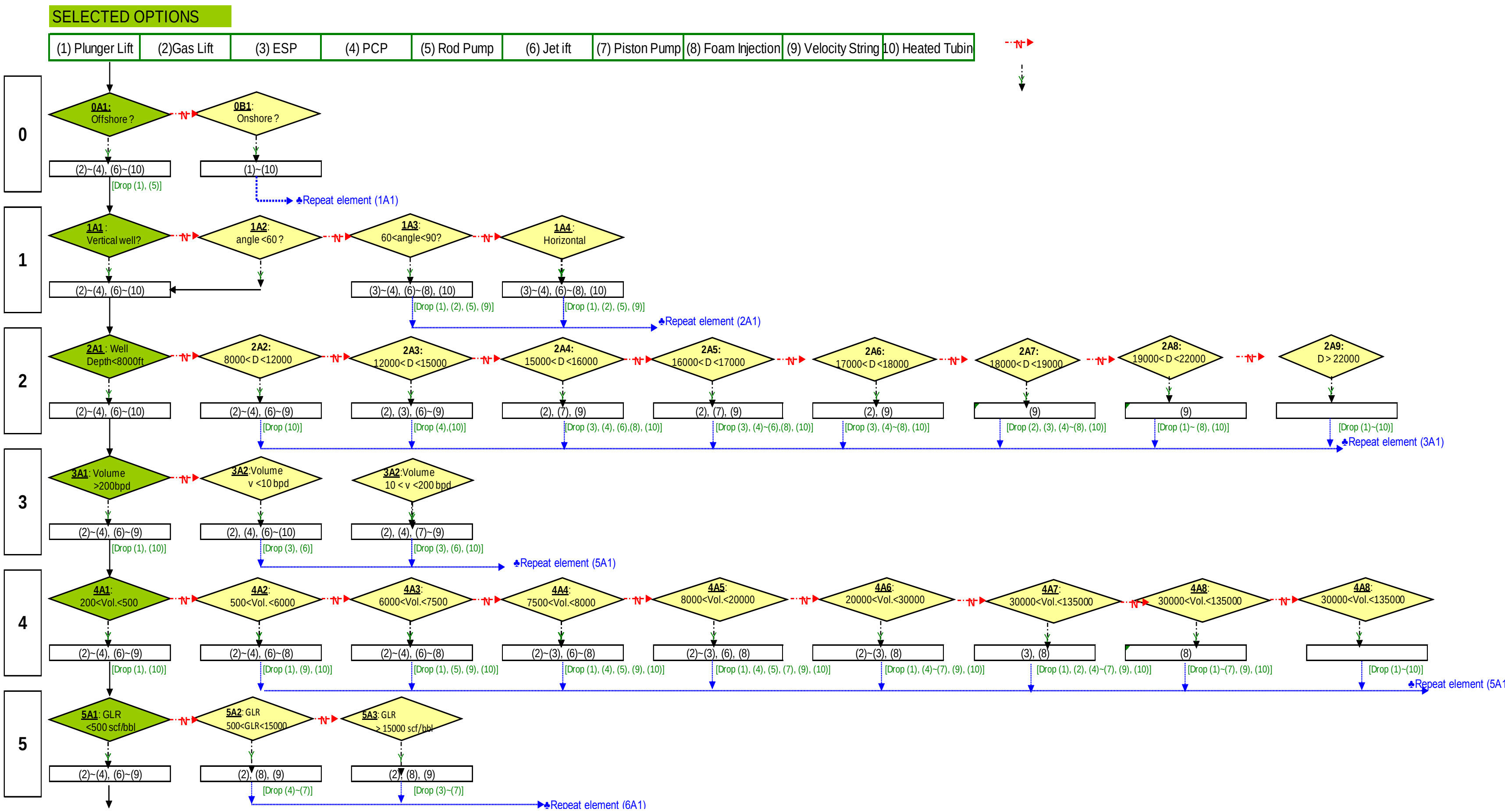
APPENDIX II

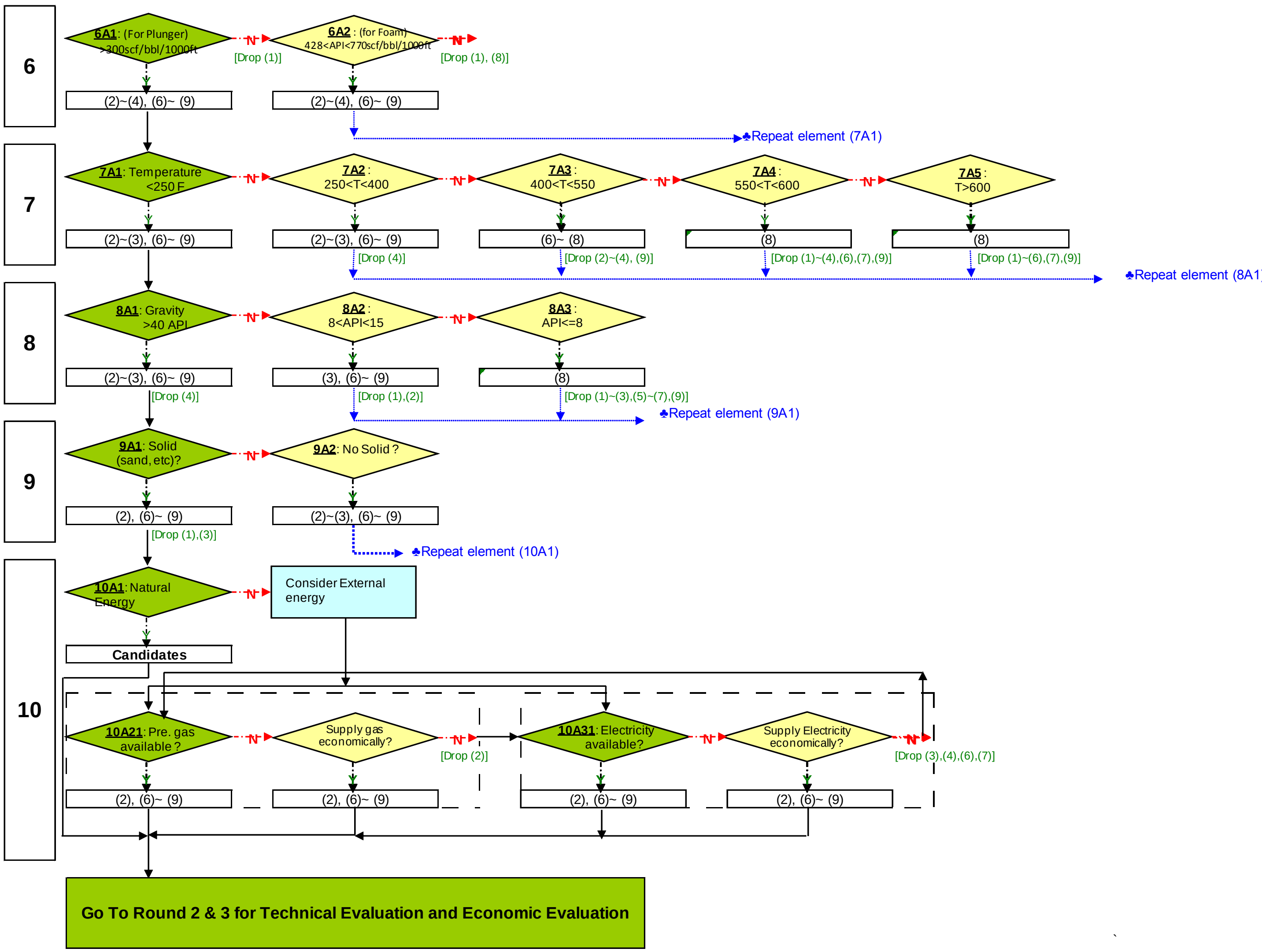
Cost of Artificial Lift Used For Gas Wells From Chevron

Artificial Lift Type	Sucker Rod Pump		ESTSP	Hydraulic reciprocating piston pump-closed loop	Conv. PCP (<250F)	I-PCP (<250F)	Mechanical lock PCP (upto 300F)	Metal-Metal PCP (>300F)
Pump description	Sucker Rod Pump with Beam Pumping Unit		Electrical Sumbersible Twin Screw Pump	3 tbg in the well connected to piston pump through BHA, closed loop power fluid (PF)	tubing retrievable PCP	rod retrievable PCP (Insert-PCP)	Mechanical lock PCP	Metal-Metal PCP
Flow Rate (gross)	200	500	500	500	500	500	500	500
Fluid Density (90% cut, 12 degree API)	0.993	0.993	0.993	0.993	0.993	0.993	0.993	0.993
Depth (ft)	2,000	2,000	2000	2,000	2000	2000	2000	2000
Downhole Pump Cost	$26,500	$46,500	160,000	$70,300	$55,000	$53,000	$56,300	
Driver Cost (e.g., pumping unit, VFD, etc.)	$50,000	$50,000	$60,000	$38,000	$0	$0	$0	$0
Tubing/ Sucker rod/ Shaft/ CT Cost	$10,000	$10,000	$0	$0	$0	$0	$0	$0
Rig/ CTU/ Crane Costs	$5,000	$5,000	$5,000	$2,500	$5,000	$5,000	$5,000	$5,000
Surface Facilities Cost (pad, controls)	$15,000	$15,000	$7,500	$15,000	$7,500	$7,500	$7,500	$7,500
Total Installed Cost	**$106,500**	**$126,500**	**$232,500**	**$125,800**	**$67,500**	**$65,500**	**$68,800**	**$12,500**
Estimated Mean Time Between Failures	2	2	2.85	0.8	2.5	2.5	2.5	2.5
Estimated Pump Repair Cost	$10,000	$10,000	$64,000	$5,100	$13,900	$12,500	$15,400	$15,900
Estimated Hoist / Rig/ CTU Cost	$5,500	$5,500	$5,500	$2,750	$5,500	$2,750	$5,500	$5,500
Average pull costs per year	$7,750	$7,750	$24,386	$9,458	$7,760	$6,100	$8,360	$8,560
Pumping System Overall Efficiency (%)	45.0%	45.0%	40%	70%	65%	65%	65%	45%
Annual Electrical cost @ $.08 / kw-hr	$3,394	$8,485	$9,545	$5,455	$5,874	$5,874	$5,874	$8,485
Total Annual Operating Cost + Prod Loss	**$11,144**	**$16,235**	**$33,931**	**$14,912**	**$13,634**	**$11,974**	**$14,234**	**$17,045**
NPV @ 10% over 10 years	**$181,822**	**$236,232**	**$461,843**	**$226,593**	**$159,653**	**$146,433**	**$165,009**	**$127,706**

APPENDIX III

Decision Tree of The Preliminary Screening Round




6
6A1: (For Plunger) >300scf/bbl/1000ft
N
[Drop (1)]
6A2 : (for Foam) 428<API<770scf/bbl/1000ft
N
[Drop (1), (8)]
(2)~(4), (6)~ (9)
(2)~(4), (6)~ (9)
♣Repeat element (7A1)
7
7A1: Temperature <250 F
7A2 : 250<T<400
7A3 : 400<T<550
7A4 : 550<T<600
7A5 : T>600
(2)~(3), (6)~ (9)
(2)~(3), (6)~ (9)
(6)~ (8)
(8)
(8)
[Drop (4)]
[Drop (2)~(4), (9)]
[Drop (1)~(4),(6),(7),(9)]
[Drop (1)~(6),(7),(9)]
♣Repeat element (8A1)
8
8A1: Gravity >40 API
8A2 : 8<API<15
8A3 : API<=8
(2)~(3), (6)~ (9)
(3), (6)~ (9)
(8)
[Drop (4)]
[Drop (1),(2)]
[Drop (1)~(3),(5)~(7),(9)]
♣Repeat element (9A1)
9
9A1: Solid (sand, etc)?
9A2: No Solid ?
(2), (6)~ (9)
(2)~(3), (6)~ (9)
[Drop (1),(3)]
♣Repeat element (10A1)
10
10A1: Natural Energy
Consider External energy
Candidates
10A21: Pre. gas available ?
Supply gas economically?
[Drop (2)]
10A31: Electricity available?
Supply Electricity economically?
[Drop (3),(4),(6),(7)]
(2), (6)~ (9)
(2), (6)~ (9)
(2), (6)~ (9)
(2), (6)~ (9)
Go To Round 2 & 3 for Technical Evaluation and Economic Evaluation

APPENDIX IV

Technical Evaluation Matrix

Considerations			Plunger	Gas lift	ESP	PCP	Rod Pump	Jet lift	Piston Pump	Foam Injection	Velocity String	Heated Tubing
1	Well Location	Offshore	0.00	0.90	0.90	0.75	0.00	0.90	0.75	0.75	0.75	0.75
		Onshore	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
2	Well Type	Vertical	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.90	0.90	0.90
		0 deg - 40 deg	0.90	0.90	0.90	0.90	0.90	0.25	0.25	0.75	0.75	0.75
		40 deg - 70 deg	0.75	0.25	0.90	0.90	0.25	0.25	0.25	0.50	0.75	0.50
		70 deg - 90 deg	0.75	0.00	0.90	0.90	0.00	0.25	0.25	0.25	0.25	0.25
		Horizontal	0.00	0.00	0.90	0.90	0.00	0.25	0.25	0.00	0.00	0.00
3	Well Depth (ftTVD)	<12000ft	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
		12000<D<15000	0.75	0.75	0.75	0.00	0.75	0.75	0.75	0.50	0.75	0.25
		15000<D<16000	0.75	0.75	0.00	0.00	0.75	0.00	0.75	0.25	0.75	0.00
		16000<D<17000	0.75	0.75	0.00	0.00	0.00	0.00	0.75	0.00	0.75	0.00
		17000<D<18000	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00
		18000<D<19000	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00
		>19000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Operating Volume (bpd)	<200bpd	0.90	0.50	0.25	0.75	0.75	0.25	0.75	0.90	0.90	0.90
		200<V<500	0.00	0.90	0.90	0.90	0.90	0.90	0.90	0.50	0.75	0.50
		500<V<6000	0.00	0.90	0.90	0.90	0.25	0.90	0.90	0.25	0.25	0.25
		6000<V<7500	0.00	0.90	0.90	0.25	0.00	0.90	0.50	0.00	0.00	0.00
		7500<V<8000	0.00	0.75	0.75	0.00	0.00	0.50	0.25	0.00	0.00	0.00
		8000<V<20000	0.00	0.50	0.50	0.00	0.00	0.25	0.00	0.00	0.00	0.00
		20000<V<30000	0.00	0.25	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		30000<V<135000	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		>135000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Considerations		Plunger	Gas lift	ESP	PCP	Rod Pump	Jet lift	Piston Pump	Foam Injection	Velocity String	Heated Tubing
5	Solid Handling	0.25	0.90	0.25	0.90	0.50	0.75	0.50	0.75	0.50	0.50
6	Paraffin Handling	0.50	0.25	0.75	0.90	0.50	0.75	0.75	0.25	0.25	0.75
7	Corrosion Handling	0.90	0.75	0.75	0.50	0.75	0.90	0.75	0.75	0.90	0.75
8	Crooked Hole	0.25	0.75	0.25	0.45	0.25	0.75	0.50	0.25	0.50	0.50
9	Scale	0.50	0.50	0.25	0.75	0.75	0.50	0.50	0.25	0.25	0.50

* Legend :
1.00 : Excellent 0.50 : Fair
0.75 : Good 0.25 : Poor 0 : limited (not appropriate)

APPENDIX V

Cost Summary for Artificial Lift Methods

Plunger

(1) Installation		Unit cost		Number of wells	Cost
	plunger	$5,000		1	$5,000
(2) Maintenance					
	plunger	$9,000	/yr		$9,000 /yr
(3) Fuel and Power					
		$0	/yr		$0 /yr

Gas lift

(1) CAPEX

	Injection Rate (MMscfd)					
	7	5	3	1.7 & 1.5 & 1	0.5	
Compressor(s)	$2,906,000	$2,621,000	$2,090,500	$1,696,250	$1,384,500	
	$2,906,000	**$2,621,000**	**$2,090,500**	**$1,696,250**	**$1,384,500**	
(2) OPEX						
5% of CAPEX	$145,300	$131,050	$104,525	$84,813	$69,225	/year
	$145,300	**$131,050**	**$104,525**	**$84,813**	**$69,225**	

(1 Compressor is assumed, which is shared with wells)

Ref: Information from operator

ESP (Gross rate = 500 STB/D)

	Unit Cost	Cost	
(1) Installation			
Downhole Pump Cost	$160,000	$160,000	
Driver Cost (e.g., pumping unit, VFD, etc.)	$60,000	$60,000	
Tubing/ Sucker rod/ Shaft/ CT Cost	$0	$0	
Rig/ CTU/ Crane Costs	$5,000	$5,000	
Surface Facilities Cost (pad, controls)	$7,500	$7,500	
	$232,500	**$232,500**	
(2) Maintenace			
Estimated Mean Time Between Failures	2.85	2.85	
Estimated Pump Repair Cost	$64,000	$64,000	
Estimated Hoist / Rig/ CTU Cost	$5,500	$5,500	
	$24,386	**$24,386**	/year
(3) Power			
$0.05 /kwh	**$9,545**	**$9,545**	/year

PCP - Electric (Gross rate = 500 STB/D) (< 250F)

	Unit cost	Number of wells	Cost
(1) Installation	$66,500	1	$66,500
(2) Maintenance	$6,900 /yr		$6,900 /yr
(3) Fuel and Power	$5,900 /yr		$5,900 /yr

PCP - gas engine drive

	Unit cost	Number of wells	Cost
(1) Installation	$50,000	1	$50,000
(2) Maintenance	$6,742 /yr	(Apply 95% maintenance of Piston')	$6,742 /yr
(3) Fuel and Power	$11,989 /yr		$11,989 /yr

Rod Pump - Electric (Gross rate 500 STB/D)

	Unit cost	Number of wells	Cost
(1) Installation	$106,500	1	$106,500
(2) Maintenance	$7,750 /yr		$7,750 /yr
(3) Fuel and Power (Annual Electrical cost)	$8,485 /yr		$8,485 /yr

Rod Pump - gas engine drive

	Unit cost	Number of wells	Cost
(1) Installation	$30,000	1	$30,000
(2) Maintenance	$6,742 /yr	(Apply 95% maintenance of Piston')	$6,742 /yr
(3) Fuel and Power	$13,079 /yr		$13,079 /yr

Jet Pump - Electric Motor Drive

(1) Installation		Unit Cost	Cost
Downhole:			
Pump proper		$3,215	$3,215
Bottom and top assemblies on pump		$1,462	$1,462
		$4,677	$4,677
Surface individual well system: **(Same as for piston pump)**			
Separator w/ cyclone cleaner, controls and valves		$12,320	$12,320
100 hp triplex pump w/accessories		$15,980	$15,980
Electric motor (460v)	85.5 hp	$1,630	$1,630
Motor-pump coupling and guard		$433	$433
4-way flow valve		$1,555	$1,555
Power fluid flowmeter		$735	$735
Misc. fittings		$600	$600
		$33,253	$33,253
		$37,930	**$37,930**
(2) Maintenace			
Surface equipment		$1,000	$1,000 /year
Replacement of nozzle and throat once year		$600	$600 /year
		$1,600	**$1,600** /year
(3) Power			
$0.05 /kwh		**$27,949**	**$27,949** /year
(95hp*0.746*24*365*0.02)			

Jet Pump - Gas Engine Drive

(1) Installation		Unit Cost	Cost
Downhole:			
Pump proper		$3,215	$3,215
Bottom and top assemblies on pump		$1,462	$1,462
		$4,677	$4,677
Surface individual well system:			
Separator w/ cyclone cleaner, controls and valves		$12,320	$12,320
100 hp triplex pump w/accessories		$15,980	$15,980
100hp gas engine	85.5 hp	$11,000	$11,000
Motor-pump coupling and guard		$433	$433
4-way flow valve		$1,555	$1,555
Power fluid flowmeter		$735	$735
Misc. fittings		$600	$600
		$42,623	$42,623
		$47,300	**$47,300**
(2) Maintenace		(electric pow er input to motor =90/0.95(eff)=95 hp	
Surface equipment	($25/hp/yr)	$2,375	$2,375 /year
Replacement of nozzle and throat once year		$600	$600 /year
		$2,975	**$2,975** /year
(3) Power			
gas cost	$4 /mcf	(Shaft HP required at pump =77/0.85(eff)=90 hp)	
fuel volume	12 /scf/hr/HP	**$35,967**	**$35,967** /year

Piston Pump - Electric Motor Drive

(1) Installation	Unit Cost	Cost
Downhole Pump Cost	$70,300	$70,300
Driver Cost (e.g., pumping unit, VFD, etc.)	$38,000	$38,000
Tubing/ Sucker rod/ Shaft/ CT Cost	$0	$0
Rig/ CTU/ Crane Costs	2500	$2,500
Surface Facilities Cost (pad, controls)	$15,000	$15,000
	$125,800	$125,800
	$125,800	**$125,800**
(2) Maintenace		
Estimated Mean Time Between Failures	0.83	0.83
Estimated Pump Repair Cost	$5,100	$5,100 /year
Estimated Hoist / Rig/ CTU Cost	$2,750	$2,750 /year
	$9,458	**$9,458** /year
(3) Power		
$0.05 /kwh	**$5,455**	**$5,455** /year

Piston Pump - Gas Engine Drive

(1) Installation		Unit Cost	Cost
Downhole:			
Pump proper		$6,840	$6,840
Bottom and top assemblies on pump		$3,707	$3,707
		$10,547	$10,547
Surface individual well system:			
Separator w/ cyclone cleaner, controls and valves		$12,320	$12,320
100 hp triplex pump w/accessories		$15,980	$15,980
75hp gas engine	48.9 hp	$8,000	$8,000
Motor-pump coupling and guard		$433	$433
4-way flow valve		$1,555	$1,555
Power fluid flowmeter		$735	$735
Misc. fittings		$600	$600
		$39,623	$39,623
		$50,170	**$50,170**
(2) Maintenace		(electric pow er input to motor =61/0.96(eff)=65 hp	
Surface equipment	($25/hp/yr)	$1,625	$1,625 /year
Replacement of pump		$5,472	$5,472 /year
(Twice per year @40%of original cost each time)			
		$7,097	**$7,097** /year
(3) Power			
gas cost	$4 /mcf	(Shaft HP required at pump =52/0.85(eff)=61 hp)	
fuel volume	12 /scf/hr/HP	**$20,553**	**$20,553** /year
	8421.295		

Foam Injection

		Unit Cost	Cost
(1) Installation			
	Luancher	$3,550	$3,550
		$3,550	**$3,550**
(2) OPEX			
	NO. of Foram Stick per day: 6		
	Foam Stick (Average $4.23 per stick)	$9,263.70	9263.7 /yr
	Ref. from hydrofoamtechnology.com	**$9,264**	**$9,264**

SPE 101276

NO of stick	bbl/d	MMft3/d	WGR STB/MMscf
6	44.03	0.60	73.34
10	30.19	0.53	56.99
14	33.34	0.57	59.00

Our simulation WGR ~ 43 to 86 STB/MMscf

Velocity String

		Unit Cost	Cost
(1) Installation (CAPEX)			
	Coiled tubing, $4.5/ft for 10000	$45,000	$45,000
	CTU 1 day	$10,000	$10,000
	Surface Equipment	$3,000	$3,000
	CT connector	$1,000	$1,000
	SubPump	$3,000	$3,000
		$62,000	**$62,000**
	Pumping unit	$68,000	$68,000
		$130,000	**$130,000**
(2) OPEX			
	Pumping unit, $/year	24000	24000
		$24,000	**$24,000**

Ref. ctliftsystems.com

Heated Tubing

		Unit Cost	Cost
(1) Installation (CAPEX)			
		9900 ft tbg dep	9901 ft tbg depth
	Heating line , $25/linear-foot	$247,500	$247,500
	(Including STSi-Wire, 1.25" HS90 Coiled tbg, Cable injection, End seals,		$0
	Fill valve assemblies, Diala HFX Dielectric oil, engineering design)		$0
	Labor for installation, 1 week, 6 people	$30,000	$30,000
	Rig workover, 1 week	$200,000	$200,000
	Topside Equipment (Control panel, Transformer, balancer)	$350,000	$350,000
		$827,500	**$827,500**
	Shipping cost, 3% of total CAPEX	$24,825	$24,825
		$852,325	**$852,325**
(2) Fuel and Power (included in OPEX)			
	Power , 50W/ft, $0.10/kWh	**$433,620**	**$433,620** /yr

Ref: tracerindustries.com

VITA

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